CITIC PACIFIC MINING

Public Submission

by CITIC Pacific Mining Management Pty Ltd

in response to

the Economic Regulation Authority's *Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016* – 2020

PART A - INTRODUCTION

1 Background

On 31 December 2014, DBNGP (WA) Transmission Pty Limited (**DBP**) submitted to the Economic Regulation Authority (**Authority**) proposed revisions to its access arrangement for the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) for the period 1 January 2016 to 31 December 2020 (**AA4 period**) (**Proposed Revisions**).

On 20 April 2015, the Authority published its Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016 – 2020 (**Issues Paper**).

This submission is made by CITIC Pacific Mining Management Pty Ltd (**CPMM**) in relation to DBP's Proposed Revisions and in response to the Authority's Issues Paper.

2 About CPMM

CPMM is an existing shipper on the DBNGP. CPMM operates a world-class magnetite mine and processing facilities at Cape Preston in the Pilbara (**Sino Iron project**), utilising natural gas for on-site generation of electricity.

When completed, the Sino Iron project will have six processing lines, producing 24 million tonnes of magnetite concentrate annually. Significant progress has already been made with the construction and operation of the first two lines, along with large-scale supporting infrastructure including the Pilbara's first greenfield port development in 40 years. All six lines are targeted for completion by the end of 2016.

The Sino Iron project is China's largest-ever overseas investment in the resources sector, delivering wide-ranging socio-economic benefits including the creation of a new downstream processing industry for Australia, significant long-term revenue streams to government, local employment, international technology transfer, and an overall strengthening of the Sino-Australian economic relationship.

Production of magnetite concentrate is energy intensive. To meet project requirements, CPMM has invested in a 450MW, low-emission combined cycle gas-fired power station. The provision of economically efficient and reliable gas haulage services is critical to the Sino Iron project.

3 Executive Summary

CPMM requests that the Authority consider the following issues in its decision making in relation to the Proposed Revisions. CPMM discusses each issue in further detail in this submission.

3.1 **Economic Climate:** a number of DBP's submissions are now obsolete due to the substantial changes to Western Australia's economic climate since DBP submitted its Proposed Revisions with the Authority.

3.2 **Rate of Return:** DBP has, in many instances, departed from the Guidelines without providing sufficient evidence to justify the departures. CPMM submits that DBP should adopt the approach set out in the Guidelines[1] so that the allowed rate of return

[1]Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), https://www.erawa.com.au/cproot/11953/2/Rate%20of%20Return%20Guidelines.PDF at 13 May 2015.

objective set out in the National Gas Rules can be achieved. CPMM does not agree with DBP's proposed approach to:

(a) the risk free rate;

(b) the new issue premium;

(c) the use of Black CAPM to modify inputs into the Sharpe Lintner CAPM; and

(d) the value of beta.

3.3 **Throughput:** DBP's forecast throughput does not reflect the current actual throughput of the DBNGP given that a number of new mining projects (Tropicana, Fortescue's Solomon operation and Roy Hill) with gas fired generation will come online during the AA4 period thereby increasing loads on the DBNGP.

3.4 **Expenditure:** DBP's forecast operating expenditure (in particular its forecast expenditure on system use gas) does not satisfy the 'Prudency Test' as set out in the National Gas Rules. The operating expenditure does not reflect lower labour costs and gas prices that have resulted from changes to the economic climate.

3.5 **Revenue Cap:** there is a risk that the introduction of a revenue cap will lead to shippers on the reference tariff[2] bearing a disproportionate share of the cost burden.

3.6 **Reference Service and Tariff:** the tariffs proposed by DBP do not account for the expected fall in tariffs following the expiry of the negotiated inflated tariff resulting from the bail out of the DBNGP in 2004.

3.7 **Reference Service Terms and Conditions:** Most of DBP's proposed changes reduce operational flexibility for shippers and increase risk for shippers. They reflect a value transfer from shippers to DBP, for which no good case has been made.

PART B – OVERARCHING COMMENTS

4 Economic Climate

4.1 The economic climate in Western Australia, and globally, has changed since DBP submitted its Proposed Revisions.

4.2 There has been a significant fall in the oil price, which has had a downwards impact on the price of LNG and may impact the price of domestic gas. The current Western Australian domestic spot gas prices can be seen in Appendix 3 and should be used as a viable source of gas supply for all West Australian natural gas consumers.

4.3 Furthermore, inflation is slowing and the costs of labour, parts, steel and pipe have fallen and are likely to continue falling over the coming years. There has been a corresponding fall in debt raising costs.

4.4 CPMM requests that the Authority take into account these factors, in particular in relation to:

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[2] Under section 2(1) of the National Gas Law, reference tariff means 'a tariff or charge for a reference service—

(a) specified in an applicable access arrangement approved or made under a full access arrangement decision; or

(b) determined by applying the formula or methodology contained in an applicable access arrangement approved or made under a full access arrangement decision.'

(a) the cost of debt;

(b) operating expenditure; and

(c) the reference tariff.

5 Risk of Discriminatory Treatment

5.1 CPMM is concerned that third parties seeking access to the DBNGP and existing shippers seeking to recontract with DBP will essentially become second-class customers on the DBNGP if they accept the reference tariff and the reference service terms and conditions proposed by DBP in its Proposed Revisions. This concern has two bases:

(a) first, there is a risk that a higher reference tariff paired with a revenue cap adjustment may lead to shippers that pay the reference tariff paying a disproportionate share of the cost burden (see para 12.2 below); and

(b) second, the reference service terms and conditions proposed by DBP may be materially less attractive than what it offers to recontracting shippers, which may distort negotiations in DBP's favour.

5.2 CPMM requests that the Authority takes into account these concerns in making its decision in relation to DBP's Proposed Revisions.

PART B – RATE OF RETURN

6 Introduction

6.1 The allowed rate of return under the National Gas Rules (**NGR**) is to be determined such that it achieves the 'allowed rate of return objective'[3] (**Objective**):

> 'that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provisions of reference services.'[4]

6.2 In accordance with rule 87(13) of the NGR, and through a rigorous consultative process, the Authority developed a set of guidelines[5] (**Guidelines**) which set out an approach to estimating an allowed rate of return that achieves the Objective. Although the Guidelines are not binding, CPMM submits that the Guidelines should not be departed from unless DBP has presented new or different evidence to the Authority which was not available at the time the Guidelines were published.

6.3 DBP has proposed an approach to rate of return which (at the time of its proposal) was estimated to yield a nominal post-tax WACC of 8.36%, comprising:

(a) a return on debt of 6.13% (nominal pre-tax);

(b) a return on equity of 11.71% (nominal post-tax); and

(c) gearing of 60% debt.

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[3] *National Gas Rules*, r 87(2).

[4] *National Gas Rules*, r 87(3).

[5] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013) https://www.erawa.com.au/cproot/11953/2/Rate%20of%20Return%20Guidelines.PDF at 13 May 2015.

6.4 In estimating its proposed rate of return, DBP has adopted an approach that departs from the Guidelines. CPMM's consideration of DBP's approach is set out in greater detail below.

6.5 CPMM has been unable to identify convincing arguments in DBP's submission as to why the Guidelines should be departed from and how its proposed approach achieves the Objective. In the circumstances, CPMM submits that DBP should adopt the approach set out in the Guidelines.

7 Cost of Debt

7.1 CPMM takes issue with two aspects of DBP's proposed approach to the cost of debt:

(a) the term of the Risk Free Rate; and

(b) the New Issue Premium.

Risk Free Rate

7.2 DBP has deviated from the Guidelines by proposing to adopt a 10 year risk free rate of 3.54% for the return on debt rather than a 5 year risk free rate. The Guidelines state that 'the risk free rate will be based on the observed yield of a 5-year term Commonwealth Government Security, averaged over a 40 day period just prior to the regulatory period'.[6]

7.3 Applying a 10 year government bond as a risk free rate proxy is inconsistent with the present value principle that the term of debt should match the regulatory update period.

7.4 CPMM submits that the risk free rate should be matched to the investment horizon or asset profile, being the AA4 period of 5 years. Accordingly, CPMM submits that the Australian 5 year bond yield should be adopted which, as at 22 May 2015, was 2.28%.[7]

7.5 CPMM notes that since DBP submitted its Proposed Revisions the economic climate has changed significantly and accordingly the 10 year bond yield has reduced. As at 22 May 2015, the 10 year bond yield was 2.94%.

7.6 CPMM submits that the most recent 5 year bond yield data should be adopted in order to take account of changes to the economic climate.

New Issue Premium

7.7 DBP proposes a new issue premium of 27 basis points be added to debt raising costs on the basis that it is more costly to raise debt in the primary markets.[8] CPMM notes that the Guidelines do not address new issue premium and submits that DBP's proposed new issue premium is too high. A 2013 Study by Goldberg and Ronn[9] found that the required new issue premium is 12.9 basis points, which is

[6] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 73.

[7] Australian Bond 5 Year Yield sourced from Bloomberg Australian Government Bond Yield on 22 May 2015.

[8] Economic Regulation Authority, *Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016 – 2020*, paragraph 165.

[9] RS Goldberg and EI Ronn, *Quantifying and Explaining the New-Issue Premium in the Post-Glass–Steagall Corporate Bond Market*, The Journal of Fixed Income (2013), 43-55

approximately half the new issue premium proposed by DBP. Accordingly, CPMM submits that a new issue premium of 12.9 basis points should be adopted.

8 Cost of Equity

8.1 CPMM takes issue with two aspects of DBP's proposed approach to the cost of equity:

(a) use of results from the Black Capital Pricing Model (**Black CAPM**) to modify inputs into the Sharpe Lintner Capital Pricing Model (**SL CAPM**); and

(b) DBP's estimate of beta.

Use of Black CAPM

8.2 DBP departs from the Guidelines by using results from the Black CAPM to modify inputs into the SL CAPM. The Black CAPM was identified in the Authority's Guidelines as being irrelevant due to a lack of theoretical foundations and empirical evidence.[10] The Authority observes in the Guidelines that 'only the Sharpe Lintner CAPM model is relevant'.[11] The Authority went on to note that the SL CAPM is the most appropriate financial model to use when calculating the return on equity as it is a well-accepted financial model[12] and has been adopted by both national and international regulators, including the Office of Gas and Electricity Markets in the United Kingdom and the New Zealand Commerce Commission.

8.3 On this basis, CPMM is concerned that use of the Black CAPM to modify inputs into the SL CAPM may produce a return on equity that does not contribute towards the achievement of the Objective.

Beta

8.4 DBP has proposed a beta of 1.26. CPMM submits that DBP overestimates the risk of its business resulting in a beta that is disproportionately high compared with other Australian and USA pipeline companies and with the All Ordinaries Index. DBP has failed to show how DBP's business is riskier than other regulated businesses, in particular other gas pipeline businesses.

8.5 In assessing DBP's proposed beta, CPMM has considered:

(a) the risks involved in delivering the reference service;

(b) the prevailing market conditions for funds; and

(c) standard industry practice financing structures.

8.6 CPMM submits that DBP's proposed beta of 1.26 is too high, on the following grounds:

(a) In selecting a range in the betastar data, DBP selected a lower bound at the 20th percentile and an upper bound at the 99th percentile which results in a

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[10] By using the Black CAPM, DBP has departed from the Guidelines which state that '*other models and approaches are considered to be not relevant within the Australian context at the current time, at least without some new developments in terms of the theoretical foundations or in the empirical evidence*': Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 115.

[11] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 113.

[12] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 109.

bias in the distribution to a higher beta when ultimately applying an intersection between the two ranges;

(b) Regulatory decisions in relation to pipelines with a similar degree of systematic risk to DBP's pipeline, such as the Authority's draft decision on ATCO Gas Australia's Mid-West South-West Gas Distribution System and the Australian Energy Regulator's draft decision on Jemena's New South Wales Gas Distribution Network, have applied a beta of 0.7;

(c) On the Authority's own analysis on beta, the Guidelines adopt a range for beta from 0.5 to 0.7; and

(d) DUET Group's (DBP's majority shareholder) current observed WACC is 4.4258%[13] which is considerably lower than the WACC proposed by DBP. This is the case despite the other assets in the DUET Group portfolio being riskier than the DBNGP as they are unregulated businesses subject to competitive forces on eastern seaboard energy markets.

Comparison of DBNGP to similar Australian pipeline businesses

8.7 CPMM submits that the DBNGP faces a lower level of risk than that faced by transmission pipelines on the East Coast of Australia (**East Coast**). East Coast gas haulage pipelines face more risk from competition due to the ever increasing number of pipelines, in response to the coal seam gas 'boom' activities.

Recent projects include:

(a) North Queensland Gas Pipeline;

(b) Queensland Link and South West Queensland Pipeline upgrade;

(c) SEA Gas Pipeline from Campbelltown to Adelaide; and

(d) Eastern Gas Pipeline.[14]

8.8 Furthermore, very few pipelines on the East Coast are covered pipelines, subject to regulation under the National Gas Law, indicating that they are subject to higher levels of competition and risk.

8.9 CPMM has analysed three Australian pipeline businesses similar to DBP (APA Group, AGL Energy Ltd and Duet Group) and found that the average beta across the three companies is 0.67.[15] This average beta is significantly lower than the beta proposed by DBP.

Comparison of DBNGP to similar USA pipeline businesses

8.10 CPMM submits that the DBNGP is exposed to less risk than businesses operating pipelines in the USA, [16] and therefore its beta should be comparatively less than USA pipeline businesses. CPMM considered a sample of 16 companies operating gas pipelines in the USA (see Appendix 2 for analysis of the sample of USA companies)

[13] Sourced from Bloomberg Terminal (14 May 2015)

[14] State of the Energy Market 2009, Australian Energy Regulator (2009) Chapter 9

[15] Betas sourced from Bloomberg Terminal (14 May 2015)

[16] See Appendix 1.

and found that the average beta across the sample was 0.779. This average beta is also considerably lower than the beta proposed by DBP.

8.11 There is an inherent higher risk associated with USA gas pipelines in this sample, compared with the DBNGP, because:

(a) there is greater competition between USA gas pipelines, a lower level of firm demand and a shorter term for firm contracted capacity in the USA; and

(b) many pipelines in the USA are going into, or participating in, high risk, unregulated ventures rather than solely competing in markets as a monopoly with multiple sources of gas supply.

Comparison of the DBNGP to the All Ordinaries index

8.12 When DBP's proposed beta of 1.26 is applied to a market risk premium of 6.5, it may be inferred that the DBNGP is riskier that the All Ordinaries index. CPMM does not agree with this notion and further submits that the beta applied should be significantly less than 1.

8.13 CPMM submits that DBNGP is low risk because:

(a) it links multiple supply areas in the Carnarvon Basin to a single market, being the Western Australian market traversed and serviced by gas delivery in DBNGP;

(b) virtually all available capacity on the DBNGP is contracted for a period beyond the next access arrangement period;

(c) counterparty risk is negligible as the majority of shippers on the DBNGP are large reputable organisations with excellent credit credentials; and

(d) DUET Group, DBP's major shareholder, has a beta of 0.655[17].

8.14 Accordingly, CPMM submits that, because DBNGP is a regulated monopoly with relatively long-term firm demand and virtually all of its capacity contracted on a firm basis for the duration of AA4 period, the risk associated with its business is relatively low and so its beta should be significantly lower than the samples referred to above. CPMM proposes that a beta of not greater than 0.7 be adopted.

9 CPMM's proposed rate of return applying the Guidelines

9.1 CPMM has proposed a nominal post-tax Weighted Average Cost of Capital of 5.56% by using DBP's model and substituting in its own values that it has reasonably determined by applying the Guidelines. CPMM has used a gearing of 60% debt and the following values:

(a) Cost of debt of 4.72%, based on the below components:

Component	Proposed value
Five year risk free rate *[See discussion in paragraphs 7.2-7.6 above]*	2.28%

[17] Sourced from Bloomberg Terminal (14 May 2015)

Component	Proposed value
New issue premium *[See discussion in paragraph 7.7 above]*	12.9 basis points
10 year debt risk premium over swap rate *[No objection to DBP's proposed value]*	1.86%
Premium between the ten year Commonwealth Government Securities and ten year swap rate *[No objection to DBP's proposed value]*	0.31%
Allowance for debt-raising and hedging costs *[No objection to DBP's proposed value]*	15 basis points

(b) Cost of Equity of 6.83%, based on the below components:

Component	Proposed value
Beta *[See discussion in paragraphs 8.4-8.14 above]*	0.7
Five year risk free rate *[See discussion in paragraphs 7.2-7.6 above]*	2.28%
Market risk premium *[No objection to DBP's proposed value]*	6.5

PART C –THROUGHPUT

10 Forecast Throughput

10.1 DBP has forecast 85% utilisation of the DBNGP over the AA4 period, starting at 727.1 TJ/d in 2016 and falling to 716.4 TJ/d in 2020. CPMM does not agree with DBP's forecast.

10.2 The full haul capacity of the DBNGP for the year ending 30 June 2015 is 845 TJ/d.[18] DBP has indicated that it has contracted for over 85% of firm full haul capacity, as announced by DUET Group on 7 August 2014. DUET also said that DBP's aggregated contracted capacity will be 58 TJ/d lower representing 7% of the previous firm full haul contracted capacity. Putting these numbers into perspective against the total gas volume throughput of all major shippers on the DBNGP (excluding volumes being delivered into the Parmelia and Goldfields gas pipelines) the daily throughput exceeds 1000 TJ, suggesting that there is 100% of the DBNGP's full haul capacity of 845 TJ/d currently contracted and such is likely to continue for the AA4 period.

10.3 Looking at actual throughput, the current average gas volume being delivered around Western Australia with the majority delivered through the DBNGP is approximately

[18] DBNGP Capacity Register, August 2014, paragraph 2.1 at http://www.dbp.net.au/wp-content/uploads/2015/01/DBNGP-Capacity-Register-as-at-July-2014.pdf at 25 May 2015.

1180TJ/d,[19] which is 39% over the 845TJ capacity of the DBNGP. With current full haul customers that took up the recontracting offer for contracted tariffs, making 'up more than 85% of firm full haul capacity'[20] (CPMM approximates 720 TJ/d) the natural conclusion is that the balance of 460 TJ/d capacity is currently being used by the remaining contracted full haul customers and part haul customers. These additional customers allow a pipeline owner to sell more capacity than it actually has (but all within the limits of the pipeline) and revenues from such should be taken into consideration by the Authority in determining tariffs going forward.

10.4 The history of volume movements through the DBNGP using gas delivery volume data from the Independent Market Operator's Gas Bulletin Board shows that 1168TJ/d is the rolling average for the life of the data compilation to date (from 1 August 2013 to 10 May 2015) and 1167 TJ/d is the average over the last 12 months (from 9 May 2014). The volume average has increased slightly for the last 6 months producing a daily average of 1181 TJ/d. This increase in volume has occurred despite a back drop of economic slowdown in the state together with the significant drop in oil and iron ore prices.

10.5 CPMM submits that the trend in increasing gas volumes will continue for at least the next 5 years (which coincides with the AA4 period) with additional gas volumes coming into the market from Gorgon 1 & 2, Wheatstone and the new Apache entity.

10.6 CPMM submits that domestic gas supply volumes are likely to be further assisted by the reduction in global LNG spot prices making sale of domestic gas in WA as profitable as sale of international LNG spot cargoes and therefore encouraging producers to divert natural gas to their domestic gas facilities as opposed to their LNG production facilities. This ability is evidenced by spare production capacity in existing facilities as shown in the Independent Market Operator's Gas Statement of Opportunities (**GSOO**).

10.7 Despite iron ore operations being scaled back, oil price reductions and the state's economy slowing; the steady throughput in gas volumes appears to have been driven partly by a fall in the spot price of gas. Moreover, demand throughput is therefore even more likely to increase as new projects come on line over the next 2 years, such as:

(a) the new Fortescue River Gas Pipeline to FMG's Solomon Hub;[21]

(b) the Tropicana Gold Mine;[22] and

(c) Roy Hill Mine.[23]

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[19] This amount is the aggregate of all gas transported. It should be slightly discounted because:
(a) Some of it covers a very short haul (e.g. gas destined for the Pilbara Pipeline); and
(b) A small quantity of gas from the Perth Basin which does not pass through the DBNGP, and is instead fed into the Parmelia Pipeline.

[20] See Appendix 4

[21] Fortescue Metals Group has signed 'a long term gas transportation agreement for the delivery of gas to reduce operating costs at its Pilbara Operations. Gas will be delivered via the existing Dampier to Bunbury Natural Gas Pipeline and the new Fortescue River Gas Pipeline, to the Power Station at Fortescue's Solomon Hub': ASX Announcement dated 16 January 2014 (See Appendix 5).

[22] Independence Group NL (IGO) announced to the market that its Joint Venture Partner AngloGold Ashanti, on behalf of the Tropicana Joint Venture entered into agreements with APA Group for the transportation of natural gas to the Tropicana Gold Mine in the eastern goldfields: ASX Announcement dated 21 July 2014 (see Appendix 6).

[23] The Roy Hill Mine will be utilising Alinta Energy's 178MW open-cycle gas-fired power station in Newman https://au.news.yahoo.com/thewest/a/26816923/roy-hill-gets-connected/ (see Appendix 7).

When completed, these infrastructure projects will open up more opportunities for neighbouring industry to tap into lower cost energy sources.

10.8 Furthermore, it is likely that over the AA4 period a carbon emissions reduction scheme will be introduced. Such a scheme would encourage use of gas over coal or diesel in power generation in the South West Interconnected System and remote mine sites, which would in turn further increase the volumes of gas through the only pipeline spanning the distance between Dampier and Bunbury which is the master pipeline for the many subservient pipelines servicing Western Australia.

PART D – EXPENDITURE

11 Operating Expenditure

11.1 Under the NGR, operating expenditure will not be added to total revenue unless it is 'such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost' (**Prudency Test**).[24]

11.2 During the current access arrangement period, DBP spent 38% less on operating expenditure (**AA3 Opex**) than it budgeted for. For the next access arrangement period, DBP has forecast a significant increase from its AA3 Opex. CPMM submits that DBP's proposed operating expenditure does not satisfy the Prudency Test as, amongst other reasons, its forecast does not reflect current (relatively) low gas prices and labour costs.

<u>System Use Gas</u>

11.3 Forecast system use gas (**SUG**) is the most significant increase in DBP's forecast operating expenditure. DBP has forecast SUG will be between $6.50/GJ and $12/GJ under a long term take or pay gas purchase agreement.[25]

11.4 However, domestic gas prices are at a historical low and are forecast to continue at relatively low prices for the next 5 years. Gas can be purchased on the spot market to capture the benefits of low gas prices.

11.5 At the time of this submission (see Appendix 3), buyers were offering to purchase gas on the gas spot market at prices between $2.20/GJ and $5.60/GJ, which produces a weighted average price of $3.01/GJ. At the same time, sellers were offering to sell gas on the spot market at similar prices, between $2.80/GJ and $5.60/GJ, which produces a weighted average price of $3.77/GJ.

11.6 CPMM submits that DBP's forecast gas prices for SUG do not pass the Prudency Test, as a prudent service provider would take advantage of low gas prices at least by diversifying its gas portfolio to purchase some gas on the spot market and some under medium term contracts.

11.7 CPMM concedes that DBP has to have access to a reliable source of gas to meet its obligations. However, DBP has some flexibility in that it can manage the linepack and SUG to effectively bid on the gas spot market for at least some of its SUG requirements. CPMM submits that the gas spot market prices are representative of the lowest sustainable cost and should be substituted for DBP's forecast gas prices.

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[24] National Gas Rules, rule 91.

[25] Economic Regulation Authority, *Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016 – 2020*, paragraph 165.

Accordingly, CPMM submits the average price allowed for SUG should be between $3.01 to $4.20/GJ.

PART E – REVENUE CAP

12 Change to Revenue Cap

12.1 The current access arrangement is based on a price cap whereby the tariff variation mechanism provides for reference tariffs to be adjusted annually for CPI.[26] DBP has proposed to move to a revenue cap. [27]

12.2 CPMM is concerned that a revenue cap will result in shippers that pay the reference tariff bearing a disproportionate share of the cost burden flowing from the discount that DBP has given to other shippers who accepted DBP's recontract deal (referred to by DUET Group in its announcement - see Appendix 4).

PART F – REFERENCE SERVICE AND TARIFF

13 Reference Tariff

13.1 The total reference tariff for a T1 full haul service under the current access arrangement period is $1.3460/GJ[28] (un-escalated to 2015). DBP proposes that the tariff be increased to $1.6530/GJ[29] as at 1 January 2016.

13.2 CPMM submits that the proposed tariff is too high, and should actually be reduced to $1.24/GJ as at 1 January 2016 (calculated using DBP's model but substituting in a WACC of 5.56% as proposed by CPMM in paragraph 9.1).

13.3 The Authority notes in its Issues Paper that 'a large proportion of DBP's customers pay charges in excess of the reference tariffs.' CPMM submits that this may no longer be the case, as DUET Group announced on 7 August 2014 that it has recontracted more than 85% of its firm full haul capacity at a tariff approximately 9.5% lower than tariffs currently payable by shippers on the DBNGP.

13.4 CPMM considers it may be appropriate for the Authority to explore DBP's actual charge, rates, actual and expected cash flows to ensure correct assumptions are considered in deciding on appropriate tariffs.

13.5 In any event, CPMM submits that the contracted tariffs at the time DBP submitted its Proposed Revisions are not an appropriate baseline from which to judge DBP's proposed reference tariff and any associated price shock, because the contracted tariffs for the current period were artificially inflated as a result of the negotiated rescue of the DBNGP in 2004 following the insolvency of its then owner, Epic Energy. As part of the rescue deal, it was agreed that:

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[26] Economic Regulation Authority, *Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016 – 2020*, paragraph 19.

[27] ''DBP has proposed the inclusion of a Revenue Cap Adjustment as a tariff variation mechanism. As a large proportion of DBP's customers pay charges in excess of the reference tariffs, DBP has proposed an approach using the concept of "regulated earned revenues". These are the revenues the benchmark efficient entity operating the DBNGP would earn with the same capacity and throughput as in actual operations, but on the assumption that all customers are paying the reference tariff'': Economic Regulation Authority, *Issues Paper on Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2016 – 2020*, paragraph 190.

[28] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 173.

[29] Economic Regulation Authority, *Rate of Return Guidelines* (16 December 2013), paragraph 173.

(a) contracted tariffs would be artificially inflated in order to enable Epic's banks to recover the full amount owing to them and effectively release the DBNGP from Epic Energy's insolvency; and

(b) the tariffs would significantly fall in 2016 in order to return to the reference tariff path.

13.6 For a history of the rescue deal referred to above and the tariff, see Appendix 8.

13.7 On the subject of tariff escalation, CPMM acknowledges that a supplier cannot reasonably foresee changes in law and taxes and make allowances for these changes in tariff pricing. Accordingly, CPMM supports tariff escalation mechanics to permit DBP to pass through to customers, on a non-discriminatory basis, its direct and mitigated costs incurred as a result of an unforeseen change in law or tax. A sound example would be the introduction of a carbon tax that resulted in DBP incurring costs that it did not allow for in its pricing (recontracted or reference). In this example, DBP should be entitled to recover its mitigated costs of complying with the new carbon tax via an increase in the tariff.

13.8 CPMM submits that the DBP proposed reference tariff variation mechanism is unnecessarily complex and so CPMM respectfully suggests the Authority continue to apply the current access arrangement's tariff variation mechanics. To get escalation right, the mechanics must move the escalation risk (more accurately, that part of escalation risk which is beyond the supplier's control) from the supplier (DBP) and place it onto the shipper so that the supplier isn't at unfair risk of under or over-recovery (**Escalation Objective**). There are a number of added complexities to achieving the Escalation Objective in the AA4 period which we provide to the Authority for its consideration:

(a) DBP's tariff variation mechanisms only apply to the shippers who will be on reference tariffs. For these shippers there must be no chance of over or under-recovery when it comes to escalation of DBP's true input costs for risk allocation to be correct.

(b) Escalation should only apply to variable input cost components in the reference tariff pricing. Therefore a flat increase in the tariff to reflect increases in CPI is an inappropriate mechanism - i.e. the non-variable component of the rate (depreciation, tax, fixed interest, loan facilities fees etc) should be excluded from CPI escalation.

(c) The majority of full haul shippers have chosen to contract their position for the AA4 period. The recontracting shippers and DBP have chosen to accept whatever risk allocation mechanism is set out in the respective contracts. Therefore, a significant portion of DBP's cost escalation risk has already been allocated in arms-length commercial dealings. This should be considered when applying reference tariff variation mechanisms in the AA4 period. Specifically, to the extent DBP agreed with the recontracting shippers that DBP would take on escalation risk, the NGO requires that that risk should stay with DBP and not be passed on to regulated shippers through the Access Arrangement.

13.9 Giving consideration to the above points, CPMM submits the portion of DBP's costs that will actually be exposed to tariff variation mechanisms should be very low and the escalation formulae used in the Authority's final decision must take this into consideration.

14 Terms and Conditions

14.1 CPMM submits that the amendments made to the Terms and Conditions are not commercially viable for third parties seeking access to the DBNGP or existing shippers seeking to recontract with DBP. There is a risk that access seekers or recontracting shippers will be forced to contract at a premium non-reference tariff in order to avoid having these terms imposed on them. The alternative is that access seekers or recontracting shippers accept the terms and conditions, and in essence are discriminated against on the DBNGP. Please see discussion in Appendix 9.

Appendix 1

Sample of Beta for USA companies

Domicile	Code	Name	Beta β
AUS	AGL	AGL Energy Ltd	0.657
AUS	DUE	DUET GROUP	0.655
AUS	APA	APA Group	0.714
AUS	SYD	Sydney Airports	1.167
AUS	TCL	Transurburban Group	0.714
USA	GEL	Genisis Energy	0.989
USA	KMP	Kinder Morgan Energy Partners	0.697
USA	PAA	Plains All American Pipeline	0.693
USA	MMP	Magellan Midstream Partners	0.758
USA	OKS	ONEOK Partners	0.763
USA	EEP	Enbridge Energy Partners	0.833
USA	MWE	Markwest Energy Partners	1.069
USA	WPZ	Williams Partners	0.694
USA	BPL	Buckeye Partners	0.781
USA	EPB	El Paso Pipeline Partners	0.632
USA	NS	NuStar Energy	0.697
USA	NGLS	Taga Resources Partners	0.917
USA	SXL	Sunoco Logistics Partners	0.67
USA	CPNO	Capano Energy	0.949
USA	BWP	Boardwalk Pipeline Partners	0.605
USA	WES	Western Gas Partners	0.722

Appendix 2

Five year Betas for USA Gas Pipeline Companies

Domicile	Code	Name	Beta β	Description
AUS	AGL	AGL Energy Ltd	0.657	AGL is one of Australia's leading integrated energy companies and largest ASX listed owner, operator and developer of renewable energy generation in the country. AGL has a diverse power generation portfolio including base, peaking and intermediate generation plants, spread across traditional thermal generation as well as renewable sources including hydro, wind, landfill gas, solar and biomass. Drawing on more than 175 years of experience, AGL sells and markets natural gas, electricity and energy related products and services to more than 3.8 million residential and small business customer accounts across New South Wales, Victoria, South Australia and Queensland. AGL also invests in and operates natural gas exploration, development and production tenements, and operates natural gas storage facilities. Listed on the Australian Securities Exchange, AGL is an S&P/ASX 50 company. AGL has been operating in Australia since 1837 and was one of its first listed companies.
AUS	DUE	DUET GROUP	0.655	DUET Group (DUET) is an ASX-listed owner of energy utility assets in Australia. Owner of the DBNGP. The Dampier Bunbury Natural Gas Pipeline (Dampier Bunbury Pipeline) is Western Australia's principal gas transmission pipeline. It is the only pipeline connecting the natural gas reserves of the Carnarvon and Browse basins on Western Australia's North West Shelf with industrial, commercial and residential customers in Perth and the surrounding regions. Natural gas supplies approximately 50% of total primary energy consumption in Western Australia. The group of companies that owns and operates the Dampier Bunbury Pipeline trades under the name of DBP Transmission (DBP).
AUS	APA	APA Group	0.714	APA Group (APA) is Australia's largest natural gas infrastructure business, owning and/or operating in excess of $12 billion of energy assets. Its gas transmission pipelines span every state and territory in mainland Australia, delivering approximately half of the nation's gas usage. APA has direct management and operational control over its assets and investments. APA also has an ownership interest in, and operates the Allgas gas distribution network as well as operating the Australian Gas Networks (formerly Envestra Limited), which together have approximately 27,000 kilometres of gas mains and approximately 1.3 million gas consumer connections. APA also owns other energy infrastructure assets such as gas storage facilities and a wind farm. In addition to Australian Gas Networks and GDI (EII), which owns the Allgas Distribution Network, APA also has equity interests in a number of energy infrastructure assets, including SEA Gas Pipeline, Energy Infrastructure Investments, EII2 and the Ethane Pipeline Income Fund. APA is listed on ASX and is included in the S&P ASX 50 Index.

AUS	SYD	Sydney Airports	1.167	Sydney Airport is Australia's busiest airport. In 2013 the airport was used by 37.9 million passengers – an average of more than 100,000 passengers each day. It is located about 8 kilometres south of Sydney's CBD and convenient transport to the city is available by both road and rail. By facilitating international trade and communications, efficient airports are vitally important to Australia's national prosperity. They are an essential part of the transport networks that all successful modern economies rely on. There are three passenger terminals at Sydney Airport.
AUS	TCL	Transurburban Group	0.714	Owner, operator and developer of electronic toll roads and intelligent transport systems.
USA	GEL	Genisis Energy	0.989	Genesis Energy, L.P. is a limited partnership focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida and in the Gulf of Mexico. It has a portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, barges and trucks. It provides an integrated range of services to refineries, oil, natural gas and carbon dioxide (CO2) producers, industrial and commercial enterprises that use sodium hydrosulfide and caustic soda, and businesses that use CO2 and other industrial gases. It operates in three segments: Pipeline Transportation, Refinery Services, and Supply and Logistics. On 3 January 2012, it acquired interests in Gulf of Mexico crude oil pipeline systems, including its 28% interest in Poseidon pipeline system, its 29% interest in Odyssey pipeline system, and its 23% interest in the Eugene Island pipeline system.
USA	KMP	Kinder Morgan Energy Partners	0.697	Kinder Morgan Energy Partners, L.P. (KMP) is a pipeline transportation and energy storage company in North America. KMP owns an interest in approximately 29,000 miles of pipelines and 180 terminals. The Company operates in five business segments: Products Pipelines, Natural Gas Pipelines, carbon dioxide (CO2), Terminals and Kinder Morgan Canada. The Company's pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products. Its terminals store petroleum products and chemicals and handle products, such as ethanol, coal, petroleum coke and steel. The Company is also a provider of CO2. On July 1, 2011, the Company acquired from Petrohawk Energy Corporation both the remaining 50% interest in KinderHawk Field Services LLC and a 25% interest in EagleHawk Field Services, LLC. On 15 December 2011, the Company acquired a refined petroleum products terminal located on a 14-acre site in Lorton, Virginia from Motiva Enterprises, LLC.
USA	PAA	Plains All American Pipeline	0.693	Plains All American Pipeline, L.P. (Plains) is engaged in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids (NGL). The term NGL includes ethane and natural gasoline products, as well as propane and butane, products, which are also commonly referred to as liquefied petroleum gas (LPG). The Company's operations are conducted directly and indirectly through its primary operating subsidiaries. Through its general partner interest in PAA Natural Gas Storage, L.P., it also owns and operates natural gas storage facilities. The

				Company operates in three segments: Transportation, Facilities, and Supply and Logistics. The Company has network of transportation, terminalling and storage facilities at various markets and in oil producing basins, as well as crude oil, refined product and LPG transportation corridors in the United States and Canada.
USA	MMP	Magellan Midstream Partners	0.758	Magellan Midstream Partners, L.P. is engaged in the transportation, storage and distribution of refined petroleum products. The Company operates in three segments: petroleum pipeline system, petroleum terminals and ammonia pipeline system. Its petroleum pipeline system, consists of approximately 9,600 miles of pipeline and 50 terminals. Petroleum terminals include storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals. Its ammonia pipeline system is representing 1,100-mile ammonia pipeline and six associated terminals. In January 2011, the Company acquired the remaining 50% undivided interest in its Southlake. In April 2011, it acquired an approximate 38-mile petroleum products pipeline segment connected to its petroleum pipeline system at Reagan, Texas. In May 2011, the Company acquired petroleum products storage tanks in Riverside, Missouri.
USA	OKS	ONEOK Partners	0.763	ONEOK Partners, L.P. (Partnership) is engaged in gathering, processing, storage and transportation of natural gas in the United States. In addition, the Company owns natural gas liquids (NGL) systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers. The Company operates in three segments: Natural Gas Gathering and Processing; Natural Gas Pipelines, and Natural Gas Liquids. On June 30, 2011, the Company acquired ONEOK Bushton Processing Inc. (OBPI).
USA	EEP	Enbridge Energy Partners	0.833	Enbridge Energy Partners, L.P. (the Partnership) owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States. As of 31 December 2011, its portfolio of assets included the approximately 6,500 miles of crude oil gathering and transportation lines and 32 million barrels of crude oil storage and terminalling capacity; natural gas gathering and transportation lines totalling approximately 11,500 miles; nine natural gas treating and 25 natural gas processing facilities with an aggregate capacity of approximately 3,255 million cubic feet per day, including plants; trucks, trailers and railcars for transporting natural gas liquids (NGLs), crude oil and carbon dioxide, and marketing assets, which provide natural gas supply, transmission, storage and sales services. The Company conducts its business through three business segments: Liquids, Natural Gas and Marketing.
USA	MWE	Markwest Energy Partners	1.069	MarkWest Energy Partners, L.P. (MarkWest Energy) is a master limited partnership engaged in the gathering, processing and transportation of natural gas; the transportation, fractionation, storage and marketing of natural gas liquids (NGLs), and the gathering and transportation of crude oil. It provides services in the midstream sector of the natural gas industry. The Company also provides processing and fractionation services to crude oil refineries in the Corpus Christi, Texas area through its Javelina gas processing and fractionation facility. As of December 31, 2011, the Company operated in four segments: Southwest, Northeast, Liberty and Gulf Coast. Effective December 31, 2011, the Company acquired the remaining 49% interest in MarkWest Liberty

				Midstream. On February 1, 2011, the Company acquired Langley processing plant.
USA	WPZ	Williams Partners	0.694	Williams Partners L.P. focuses on natural gas transportation; gathering, treating, and processing; storage; natural gas liquid (NGL) fractionation, and oil transportation. As of December 31, 2011, The Williams Companies, Inc. (Williams) owned 70% limited partnership interest in the Company and all of its 2% general partner interest. Williams is an energy infrastructure company. The Company operates in two segments: Gas Pipeline, and Midstream Gas & Liquids. Its Gas Pipeline segment includes its interstate natural gas pipelines and pipeline joint venture investments. Its Midstream Gas & Liquids segment includes its natural gas gathering, treating and processing business and consists of wholly owned and partially owned subsidiaries. In May 2011, the Company acquired from Williams an additional 24.5% interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream). On 17 February 2012, the Company acquired 100% interest in certain entities from Delphi Midstream Partners, LLC.
USA	BPL	Buckeye Partners	0.781	Buckeye Partners, L.P. (Buckeye) is a master limited partnership. The Company owns and operates independent refined petroleum products pipeline systems in the United States, with approximately 6,100 miles of pipeline and 100 active products terminals that provide aggregate storage capacity of over 64 million barrels. The Company operates in five segments: Pipelines & Terminals, International Operations, Natural Gas Storage, Energy Services and Development & Logistics. On July 19, 2011, it acquired a terminal in Bangor, Maine (Bangor Terminal) with approximately 140,000 barrels of storage capacity. On May 11, 2011, the Company sold its 20% interest in West Texas LPG Pipeline Limited Partnership (WT LPG). On 18 January 2011, the Company completed the purchase of First Reserve's interest in BORCO.
USA	EPB	El Paso Pipeline Partners	0.632	El Paso Pipeline Partners, L.P. owns and operates interstate natural gas transportation and terminalling facilities. As of 31 December 2011, the Company owned Wyoming Interstate Company, L.L.C. (WIC), Southern LNG Company, L.L.C. (SLNG), Elba Express Company, L.L.C. (Elba Express), Southern Natural Gas Company, L.L.C. (SNG) and an 86% interest in Colorado Interstate Gas Company, L.L.C. (CIG). In March 2011, the Company acquired an additional 25% interest in SNG from El Paso Corporation (El Paso). In June 2011, it acquired the remaining 15% interest in SNG and an additional 28% interest in CIG from El Paso. During the year ended December 31, 2011, it acquired the remaining 40% general partner interest in SNG.

USA	NS	NuStar Energy	0.697	NuStar Energy L.P. (NuStar Energy) is engaged in the terminalling and storage of petroleum products, the transportation of petroleum products and anhydrous ammonia, and petroleum refining and marketing. It has three segments: storage, transportation, and asphalt and fuels marketing. Its assets included 66 terminal and storage facilities providing 84.6 million barrels of storage capacity; 5,480 miles of refined product pipelines with 21 associated terminals providing storage capacity of 4.5 million barrels and two tank farms providing storage capacity of 1.2 million barrels; 2,000 miles of anhydrous ammonia pipelines; 940 miles of crude oil pipelines with 1.9 million barrels of associated storage capacity; two asphalt refineries with a combined throughput capacity of 104,000 barrels per day and two associated terminal facilities with a combined storage capacity of 5.0 million barrels, and a fuels refinery with a throughput capacity of 14,500 barrels per day and 0.4 million barrels.
USA	NGLS	Taga Resources Partners	0.917	Targa Resources Partners LP is a limited partnership formed by Targa Resources, Corp (Targa). The company is a provider of midstream natural gas and natural gas liquid (NGL) services in the United States and is engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting, terminalling and selling NGLs, NGL products, refined petroleum products and crude oil. It operates in two divisions: Natural Gas Gathering and Processing, which include Field Gathering and Processing and Coastal Gathering and Processing, and Logistics and Marketing, which includes Logistics Assets and Marketing and Distribution. On 15 March 2011, it acquired a refined petroleum products and crude oil storage and terminalling facility in Channelview, Texas. On 30 September 2011 it acquired refined petroleum products and crude oil storage and terminalling facilities in two separate transactions.
USA	SXL	Sunoco Logistics Partners	0.67	Sunoco Logistics Partners L.P. owns and operates a logistics business, consisting of a portfolio of complementary pipeline, terminalling, and acquisition and marketing assets which are used to facilitate the purchase and sale of crude oil and refined products. The Company operates in four segments: Refined Products Pipelines, Terminal Facilities, Crude Oil Pipelines, and Crude Oil Acquisition and Marketing. In May 2011, it acquired an 83.8% interest in Inland Corporation (Inland) from Sunoco and Shell Oil Company. In July 2011, it acquired the Eagle Point tank farm and related assets from Sunoco. In August 2011, it acquired a crude oil acquisition and marketing business from Texon L.P. consisting of a 75 thousand bpd crude oil purchasing business and gathering assets in 16 states, primarily in the mid-continent United States. In September 2011, it acquired a refined products terminal, located in East Boston, Massachusetts, from affiliates of ConocoPhillips.

USA	CPNO	Capano Energy	0.949	Copano Energy, L.L.C. (Copano) is an energy company engaged in the business of providing midstream services to natural gas producers, including gathering, transportation and processing of natural gas, fractionation and transportation of natural gas liquids (NGLs) and other related services. Copano's assets are located in Texas, Oklahoma, Wyoming and Louisiana, and include approximately 6,800 miles of active natural gas gathering and transmission pipelines, and natural gas processing plants. Copano operates in three segments: Texas, Oklahoma and Rocky Mountains. On January 18, 2011 the Company announced that it had formed Liberty Pipeline Group, LLC (a 50/50 joint venture with a subsidiary of Energy Transfer Partners) to construct, own and operate a 12-inch NGL pipeline (the Liberty pipeline). On February 2, 2011, it acquired puts for normal butane, isobutane, propane and West Texas Intermediate crude oil.
USA	BWP	Boardwalk Pipeline Partners	0.605	Boardwalk Pipeline Partners, LP is a limited partnership company. The Company owns and operates three interstate natural gas pipeline systems including integrated storage facilities. Its business is conducted by its primary subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries), which consist of integrated natural gas pipeline and storage systems. During the year ended 31 December 2011, it formed Boardwalk Midstream, LP (Midstream), and its operating subsidiary, Boardwalk Field Services, LLC (Field Services), which is engaged in the natural gas gathering and processing business. In December 2011, it acquired a 20% interest in HP Storage.
USA	WES	Western Gas Partners	0.722	Western Gas Partners, LP (the Partnership) is a master limited partnership (MLP) organized by Anadarko Petroleum Corporation to own, operate, acquire and develop midstream energy assets. The Partnership operates in East and West Texas, the Rocky Mountains and the Mid-Continent and is engaged primarily in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, natural gas liquids (NGLs) and crude oil for Anadarko and third-party producers and customers. As of 31 December 2011, the Company's assets consist of 11 gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline, and interests in a gas gathering system and a crude oil pipeline. Its assets are located in East and West Texas, the Rocky Mountains , and the Mid-Continent. On 13 January 2012, the Partnership completed the acquisition of Anadarko's 100% ownership interest in Mountain Gas Resources, LLC.

Appendix 3

Summary of Offers to Purchase on the GasTrading Spot Market for April 2015[30]

[30] Gas Trading Australia Pty Ltd http://www.gastrading.com.au/spot-market/historical-prices-and-volume.html at

Appendix 4

ASX Announcement of Duet

DUET Company Limited
ABN 93 163 100 061
DUET Investment Holdings Limited
ABN 22 120 456 573
DUET Finance Limited
ABN 15 108 014 062
AFS Licence No. 269287

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7 August 2014

ASX RELEASE

DBP RECONTRACTS WITH ITS SHIPPERS

DUET Group (DUET) is pleased to announce that DBP has reached agreement to recontract with shippers representing most of its firm full haul capacity under its Standard Shipper Contracts (New SSCs).

DBP will now have tariff certainty for more than 85% of DBP's aggregate firm full haul contracted capacity (including Alcoa's exempt contract). This means that less than 15% of DBP's firm full haul contracted capacity will now be subject to the 2016 regulatory tariff determination.

The tariff payable under the New SSCs represents an initial reduction of approximately 9.5% to DBP's existing Standard Shipper Contract (Original SSC) tariff. The New SSC tariff will be escalated annually. The contracts retain the existing take-or-pay tariff structure and extend the contract term with participating shippers to between 2025 and 2033 (with two further five year extension options)[1].

As part of the agreement, some of DBP's shippers (the 2014 Shippers) have brought forward a portion of their relinquishment rights[2]. As a result, DBP's aggregate contracted capacity from 1 July 2014 will be 58TJ/day lower, representing around 7% of previous firm full haul contracted capacity.

DUET's CEO, David Bartholomew said, "This is a positive outcome for DBP. Recontracting reinforces DBP's strong long term shipper relationships and underpins Western Australia's most important energy infrastructure asset. Recontracting ahead of the 2016 regulatory tariff determination was compelling for both DBP and its shippers. By recontracting now, we have been able to secure revenue certainty for DBP and certainty on gas transportation costs for our shippers."

Mr Bartholomew added, "Recontracting provided DBP with the opportunity to reset and extend its hedge book, capturing the benefit of current low forward base interest rates. The resulting lower forecast interest expense is expected to largely offset the cash flow impact of lower forecast gas transportation revenues for DBP in the current financial year. Accordingly, the DUET Boards have reaffirmed DUET's FY15 distribution guidance of 17.5 cents per stapled security."

Attached is a copy of DBP's media release.

For more enquiries, please contact:

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End notes

1. The Original SSCs had a term of 15 years, with two options of five years each. Note that:

   - capacity contracted in 2004 had various contract terms with expiry between October 2019 and December 2020;
   - certain capacity for delivery to South West CoGeneration expires on 26 March 2016; and
   - capacity contracted as a result of any expansions undertaken since 2004 had contract terms with expiry 15 years after the commissioning of each capacity expansion.

2. Under the Original SSCs, each of DBP's shippers had the opportunity to relinquish 10% of their contracted capacity each year from 2016. The New SSCs provide for that relinquishment right to be deferred from 2016 to 2021, with some amendments as described below.

   Under the New SSCs, after 1 January 2021, the 2014 Shippers each have the ability at least once in each 12 month period (or on a calendar year basis for one shipper) to relinquish capacity. Each relinquishment amount may not be more than a certain percentage per year, (ranging from 10% (in most cases) to 30%) of the aggregate of:
   - the Shipper's total contracted capacity as at the date of the New SSCs; and
   - (in most cases) requested T1 capacity granted after the date of the New SSCs for at least 10 years;

   less any capacity traded, assigned or disposed of or relinquished in other circumstances.

   One shipper has the right to accumulate the annual relinquishment percentage amount from 2016 onwards and exercise that accumulated relinquishment between 2021 and 2025.

   The 2014 Shippers also have additional relinquishment rights from 1 January 2021 which apply to varying amounts of capacity in various circumstances (which differ between the 2014 Shippers).

   Prior to 31 December 2020, there are rights to a relinquishment of an aggregate of no more than 5.12 TJ/day, or greater amounts in the event of certain plant closures.

Media Statement

7 August 2014

DBP Successfully Completes Recontracting Negotiations

DBP is pleased to announce that it has successfully completed negotiations with the majority of its shippers that contract for firm full-haul gas transportation capacity on the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The renegotiated Standard Shipper Contracts (New SSCs) establish the tariff payable by the shippers for a period that extends from July 2014 until December 2020. The parties have also agreed to extend the term of the New SSCs to between 2025 and 2033 (with two further five year extension options).

The successful recontracting materially reduces DBP's financial risk profile by significantly improving the business' contract coverage beyond 2020.

Shippers who have agreed to the New SSCs will benefit from greater certainty of their gas transportation costs over this time period compared to the potential outcomes, when the ERA resets the regulated tariff, effective 1 January 2016.

Importantly, the contract term extension and greater volume certainty of the New SSCs has enabled DBP to reset its interest rate hedging program to take advantage of current low base interest rates.

DBP's Chief Executive Officer, Mr. Stuart Johnston, said "This is an excellent outcome for both DBP and its key Shippers. It demonstrates that it's possible to reach a pragmatic commercial outcome, providing greater certainty over the medium term."

ENDS

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DBP

DBP Transmission is the trading name of the DBNGP group of entities that purchased the Dampier to Bunbury Natural Gas Pipeline in October 2004. DBP is majority owned by DUET Group (80%, in aggregate), with Alcoa a 20% minority owner.

The DBNGP

The Dampier to Bunbury Natural Gas Pipeline (DBNGP) is the only natural gas pipeline connecting the Carnarvon Basin on Western Australia's North-west Shelf with industrial, commercial and residential customers in Perth and the surrounding region. The pipeline runs from the Burrup Peninsula, near Dampier, to Bunbury in the south-west of the State.

Appendix 5

ASX Announcement of Fortescue Metals Group

16 January 2014

The Companies Officer
Australian Securities Exchange Ltd
2 The Esplanade
Perth WA 6000

Dear Sir

Fortescue announces Natural Gas Transportation Agreement to lower costs at Pilbara operations

Fortescue Metals Group (ASX: FMG, Fortescue) is pleased to announce the signing of a long term Gas Transportation Agreement for the delivery of gas to reduce operating costs at its Pilbara operations. Gas will be delivered via the existing Dampier to Bunbury Natural Gas Pipeline and the new Fortescue River Gas Pipeline, to the Power Station at Fortescue's Solomon Hub, 60 kilometres north of Tom Price.

The 270km Fortescue River Gas Pipeline will be built, owned and operated by the FRGP Joint Venture owned by DBP Development Group (a wholly-owned subsidiary of DUET Group) and TEC Pilbara Pty Ltd (a wholly-owned subsidiary of TransAlta Corporation). TransAlta Corporation is the owner and operator of the Solomon Power Station.

The development of the Fortescue River Gas Pipeline is a key component of Fortescue's broader strategy to reduce energy costs and carbon emissions. The conversion of the 125 megawatt Solomon Power Station from diesel to gas will underpin the initial stage of the Fortescue River Gas Pipeline, and is expected to save Fortescue approximately US$20 million per annum.

Fortescue has secured Foundation Shipper Rights under the Gas Transportation Agreement which provide considerable flexibility to increase gas volumes. The Fortescue River Gas Pipeline is expected to be operational early 2015 and has the potential to open up long term growth across the Pilbara, with significant extension and expansion opportunities.

Fortescue CEO Nev Power said the company was committed to reducing energy costs and carbon emissions across its mining operations. "The pipeline to Solomon allows Fortescue to reduce operating costs and play a significant role in cutting emissions by switching stationary power generation from diesel to clean natural gas," Mr Power said. "The Fortescue River Gas Pipeline also represents a significant step in the gasification of the East Pilbara to the lasting benefit of the state of Western Australia. TransAlta, our existing partner at Solomon, and DDG have outstanding reputations with proven capabilities within the energy infrastructure industry. Their expertise will allow Fortescue to focus on its core business of efficient, low cost delivery of iron ore to customers in China and South East Asia."

Yours sincerely
Fortescue Metals Group Ltd

Mark Thomas
Company Secretary

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Appendix 6

ASX Announcement of Independence Group

ASX Release

Independence Group

21 July 2014

GAS PIPELINE PROJECT TO FUEL TROPICANA GOLD MINE

Independence Group NL ("Company") (ASX: IGO) is pleased to advise that AngloGold Ashanti (AGA), on behalf of the Tropicana Joint Venture (TJV) (IGO 30%, AGA – 70% and manager), has entered into agreements with APA Group (APA) for the transportation of natural gas to the Tropicana Gold Mine (TGM) in the eastern goldfields.

Under the agreements APA will construct a new 292km gas pipeline which will connect TGM to APA's Goldfields Gas Pipeline and Murrin Murrin lateral. The existing power generator at TGM, Kalgoorlie Power Systems (KPS), a subsidiary of Pacific Energy, will change out the diesel generators at Tropicana and replace these with gas fired generators. Highlights include:

- TJV power generation costs are expected to reduce by 12%-15% which will result in a reduction in cash costs of about $25 to $30 per ounce of gold;
- Power costs more certain with links to CPI, reducing exposure to diesel price volatility;
- Fewer truck movements to and from TGM and as a result, lower road maintenance costs;
- Natural gas is a cleaner fuel, which will result in lower greenhouse gas emissions.

"Generating Tropicana's power requirements from gas fired power generators will reduce TGM's dependence on trucked diesel fuel as well as reduce operating costs," IGO's Managing Director, Peter Bradford said. "We would like to thank the AngloGold Ashanti feasibility and legal team for their efforts in advancing this project and finalising the various agreements which provide the opportunity to start generating power from gas powered generators in the first half of CY2016. IGO understands that key terms for the supply of gas to Tropicana are very close to being finalised with a major gas supplier. A formal gas supply agreement is expected to be finalised soon after."

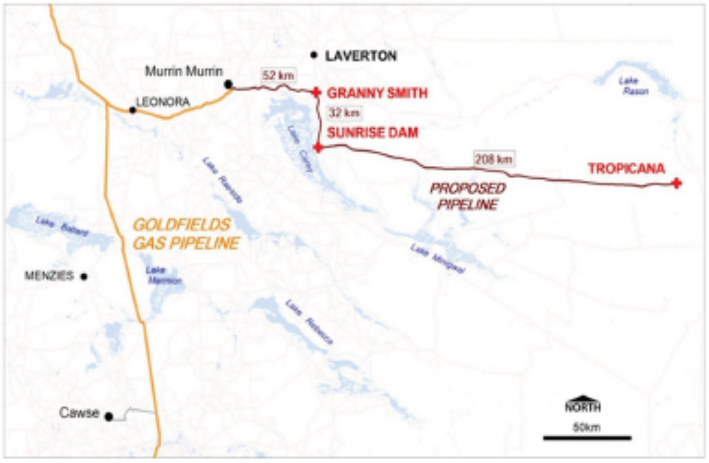

Figure 1 – Proposed pipeline construction (in red)

Background Information

During the feasibility study for the TGM gas was considered along with several other alternative power supply options. For a number of reasons the gas option was deferred until after the construction of the TGM. Tropicana poured first gold on 26 September 2013 and ramp-up to nameplate capacity was completed in the month of March 2014.

For further information contact:

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Independence Group NL
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Appendix 7

Media Article[31]

Roy Hill gets connected

Peter Klinger
March 27, 2015, 6:15 am

Share

The iron ore price may be against Gina Rinehart but at least her $10 billion Roy Hill project has gained power.

Alinta said yesterday it had completed construction and commissioning of a 121km long, 200 kilovolt transmission line from its Newman power station to the Roy Hill mine site, ahead of schedule and within its undisclosed budget.

Rinehart ramps up high costs protest

The line is a key plank in Roy Hill's development, ahead of a target to produce first shipments of ore in September.

For Alinta, it ends uncertainty around the future of its 178 megawatt gas-fired power station in Newman, which was on the verge of redundancy after previous anchor customer BHP Billiton decided to build its own electricity generator.

The Roy Hill line adds to the increasing amount of power infrastructure in the region.

The owner of the Dampier-to-Bunbury gas pipeline last week completed construction of the 270km Fortescue River Gas Pipeline. The new line runs from the Dampier-to-Bunbury to Fortescue's Solomon operation to fuel TransAlta's 125MW station.

The private-equity owned Alinta, which has staked its future growth on increased business in the Pilbara, remains in a tussle with State-owned utility Horizon Power for the right to supply Roy Hill's port operations at Port Hedland. Roy Hill needs up to 25MW at Port Hedland, and both Alinta and Horizon have uncontracted electricity available.

The West Australian

Share

[31]The West Australian <https://au.news.yahoo.com/thewest/a/26816923/roy-hill-gets-connected/> at 22 May 2015

Appendix 8

Tariff History

1. In 1998, Epic Group purchased the DBNGP for approximately $2.4 billion as part of the then State Government's privatisation process.[32]

2. The Authority determined, in its approved Access Arrangement for the period of 2000-2004, that the initial capital base of the DBNGP was approximately $1.55 billion[33] – roughly $300 million less than the debt Epic owed to the consortium of banks to finance the purchase of the pipeline. Epic consequently entered insolvency which created the need for an acquisition of the pipeline on terms that would see the banks recover the debt owing to them.

3. Macquarie developed a pipeline "rescue deal" that featured the following:

    a) the DBNGP Consortium (comprising DUET, Alinta Limited and Alcoa of Australia Limited), referred to here as "DBP", purchased the pipeline for $1.86 billion.[34] The purchase allowed the banks to recover the full amount owing to them and effectively released the pipeline from Epic Energy's insolvency; and

    b) the major shippers on the DBNGP entered negotiations with DBP to secure long term capacity rights in the DBNGP and major capacity expansions. The negotiations continued intensively up to the execution of a new suite of contracts by all major shippers and DBP in October 2004 which came to be known as the "standard shipper contracts" (**SSC's**).

4. The SSC's accounted for approximately 95% of the then current pipeline capacity, and specified an agreed tariff profile for a term of 11 years until 2016, after which the tariff was to revert to the Reference Tariff established by the Authority under an approved Access Arrangement at that time.[35]

5. Three important outcomes of the rescue deal were that:

    a) the tariff payable by shippers under their SSC's was higher than the reference tariff forecast to be approved by the Authority for the period from 2004 to 2016; [36]

    b) the quantum of the tariff over-payment was intended to equal the roughly $300m shortfall;[37] and

    c) the intention of the parties entering into the SSC's on the date of executing the SSC was that, with effect from 1 January 2016, the base tariff would be adjusted so that the base T1 tariff, T1 capacity reservation tariff and T1 commodity tariff fell back to

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[32] Alcoa World Alumina Australia, *Submission to the Productivity Commission on the Review of the National Third Party Access Regime for Natural Gas Pipelines*, 15 September 2003, available at: http://www.pc.gov.au/inquiries/completed/gas/submissions/alcoa_world_alumina_australia/sub065.pdf

[33] Economic Regulation Authority, *Approved Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 30 December 2003, page 13

[34] The Age, *Pipeline epic to end*, 26 October 2004, available at: http://www.theage.com.au/articles/2004/10/25/1098667688219.html?from=moreStories

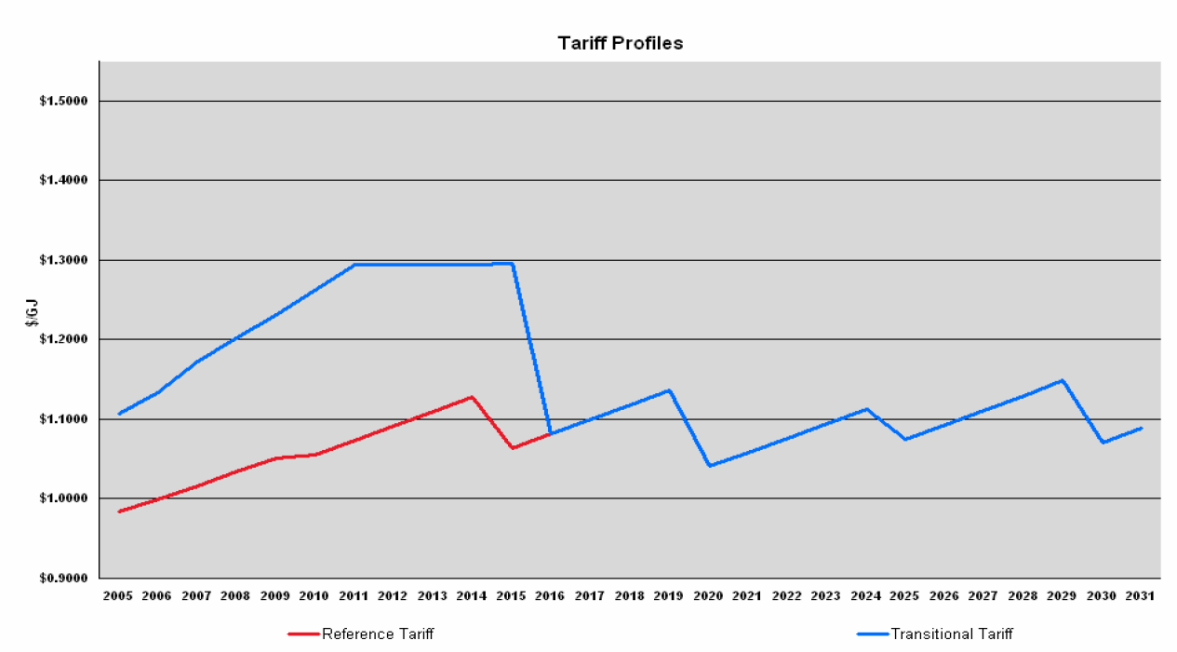
[35] Diversified Utility and Energy Trusts (DUET), *Product Disclosure Statement*, 19 November 2004, pages 45, 47

[36] Ibid, page 46.

[37] Ibid, page 46.

the level of the firm service Reference Tariff.[38] It was expected that on 1 January 2016 the applicable regulated tariff would be substantially lower than the inflated contractual tariff.

6. The expectation of the parties entering into the SSC's as to the future tariff path was enshrined by including the tariff model in the SSC's themselves - the "tariff cliff" that shippers and DBP expected to occur at the beginning of 2016 was represented in the following graph that has been taken from the 2004 SSC:



7. From one perspective, the 2004 negotiations and parties' expectations are ancient history, and the ERA's job is simply to apply the NGL and NGR in this reset to determine the appropriate reference tariff for the coming access arrangement period.

8. But CPMM submits that the history is relevant for 2 reasons:

   a) First, it is important to remember that the contractual tariff being paid by most shippers before this reset (or immediately before the 2014 recontracting), is an artificially inflated tariff imposed to allow the pipeline's rescue from insolvency, and is a wholly inappropriate comparator for determining whether there is an upwards or downwards "tariff shock" as a result of the current reset.

   b) Second, more generally, CPMM submits that the NGO will be best served if DBP is held to the spirit of the 2004 rescue. The essence of the deal in 2004 was that shippers would pay an upfront premium tariff to pay out the banks, with a promise of tariff relief from 2016 onwards. The concern among shippers at the time was that DBP may try to capture the up-front benefit but avoid the post-2016 cost, by shaping its tariff path and regulatory activity in the intervening years in a way which caused the post-2016 result to be more favourable to it than the original bargain. CPMM submits that if the ERA were to allow that outcome, it would undermine the reason for the shippers' paying the premium tariff in the early years, would undermine the commercial deal and hence disincentivise other such commercial transactions in the future, and it would certainly not be in the long term interests of shippers as required by the NGO.

[38] Ibid, page 153.

Appendix 9

CPMM review of DBP proposed Terms and Conditions

1. The following tables reproduce Tables 2 and 3 from DBP's Supporting Submission 4, with a column added to set out CPMM's comments.

2. In general, DBP's proposed amendments are an attempt to shift a substantial amount of risk to the shipper, and to remove a substantial degree of operational convenience from the shipper. DBP's explanations for these changes are not always wholly accurate, playing down what are in some cases major commercial amendments. The net effect is to substantially reduce the value of the service offered.

3. Many of the provisions now sought to be amended in DBP's favour, resulted from an arms' length negotiation in 2004 of what came to be called the 'Standard Shipper Contract'. They therefore can be assumed to reflect a reasonable risk/flexibility compromise between the pipeline operator and the shipper. From the pipeline operator's perspective, they are no doubt less than ideal, as is always the way with negotiated compromises.

4. CPMM asks the regulator to be vigilant to ensure that DBP does not try to use the lack of a commercial counterparty in the regulatory process to implement contractual changes it would be unable to achieve in a commercial negotiation (eg. which it was unable to achieve in the 2004 negotiations). The closest recent proxy to those negotiations is the recent recontracting. CPMM does not know the terms on which recontracting shipper have recontracted, but suggests to the regulator that there can be no sound reason for the regulated reference service to be on materially worse terms for a shipper than DBP was able to secure from the arms-length recontracting.

5. In fact, on the contrary, there are sound reasons why the recontracting shippers' service should be materially the same as the reference service, as follows. Although shippers and the pipeline operator should of course always be free to agree any terms they like outside the regulatory sphere, if the ERA were to allow a situation to occur in which the majority of capacity had been recontracted on terms which then turned out to be materially more favourable than the reference service, this would:[39]

    a) Skew the market for future negotiations, because any future prospective shipper's alternative to a negotiated outcome will be a less attractive reference service than is enjoyed by most of its competitors. This will further imbalance bargaining power in the pipeline operator's favour.

[39] The following discussion is hypothetical because CPPM does not know the terms of any recontracting shippers' contract. However, CPPM submits that the risk of these adverse consequences would justify the ERA's investigating the matter by examining those terms.

b) Create a situation in which DBP could at a future access reset argue that there should be an additional, premium service, a "T1 Gold Class" in effect, which enjoys the superior risk and flexibility position contained in those other contracts and, naturally, attracts a premium tariff. If this occurred, DBP would have engineered a situation in which the current "standard" service was able to be re-characterised as a "premium" service, simply by downgrading the comparator reference service terms and conditions in the current access reset.

c) Distort competition in upstream and downstream markets, by creating a situation in which some but not all competitors have access to the risk profile and operational flexibility of the more favourable terms.

6. CPMM is not aware of any actual operational problems for DBP arising out of the current terms. DBP has operated the pipeline successfully for the last 11 years with these terms in place. Further, any suggestion by DBP that the previous terms are not workable, would need to be tested by the ERA examining what DBP was prepared to sign on to with the recontracting shippers.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
2. SUMMARY OF SUBSTANTIVE CHANGES					
2.1	Definition of Carbon Cost	Definitions	Insert the words underlined "Carbon Cost means any costs (<u>for the avoidance of doubt, including penalties if that is how such costs are described in the relevant Law</u>) arising in relation to the management of and complying with any obligations or liabilities that may arise under any Law in relation to greenhouse gas emissions. For the avoidance of doubt, such costs may include the costs reasonably incurred by the Operator *or its Related Bodies Corporate* of actions taken by it to reduce greenhouse gas emissions or mitigate their effect and the costs incurred in acquiring and disposing of or otherwise trading emissions permits.	The Carbon Farming Initiative Amendment Bill that has been passed by both houses of Parliament appears to set up a system that looks at past emissions of the relevant entity and then sets targets for emissions in the future. Where those targets are exceeded, a penalty is imposed, unless the situation is declared not to be an excess emissions situation or permit trading occurs. See sections 22XE and section 22XF of the proposed amendments to the NGER Act. • This mechanism exposes DBP to a risk of additional costs with respect to which it has little or no control for the following reasons: Emissions from the DBNGP increase relative to increases in utilisation of capacity: lower usage of capacity means lower fuel gas costs. Higher usage means	The Operator should be permitted to pass through only its *direct* costs and, in respect of costs reasonably incurred to reduce greenhouse gas emissions or mitigate their effect, only those *direct* costs to the extent that they do not exceed the direct costs avoided by taking those actions. To the extent that the DBNGP is a designated large facility and the Operator (or one of its Related Bodies Corporate) is a relevant emitter for the purposes of the emission reduction safeguard mechanism due to commence under the *Carbon Farming Initiative Amendment Act 2014* on 1 July 2016, CPMM understands that relevant emitters will be able to

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				higher usage of fuel gas as more compressors are turned on. Therefore as demand grows over time, emissions on the DBNGP will increase, which could trigger the penalty imposition even though DBP is acting in a prudent manner and seeking to optimise fuel consumption. • There is no certainty that permits will be available. • Though DBP will seek to minimise the costs, if a penalty is imposed due to higher fuel consumption by reason of increased demand, the existing tariff will not cover such cost and the Reference Tariff Variation Mechanism will not stretch to allow recovery of such penalties if Carbon Cost is not defined to include them.	surrender prescribed carbon units if required to reduce the net emissions number for a facility to the baseline emissions number to avoid an excess emissions situation occurring, and thus avoid the imposition of a penalty. Since the Operator may vary the reference tariff for Tax Changes (which include Carbon Costs) to recover the cost of acquiring prescribed carbon units, CPMM rejects the proposed change to "Carbon Cost" to include penalties, which the Operator can avoid by properly managing and complying with its obligations or liabilities under any Law in relation to greenhouse gas emissions. This would also prevent the Operator (or its Related Bodies Corporate) from reneging on any other management or compliance obligations under any other Law relating to greenhouse gas emissions that may be introduced during the access arrangement period.
2.2	Definition of Major Works	Definitions 17.2(d) 18(e) 18(g)	Amend to include Planned Maintenance in definition of Major Works The following consequential changes are also proposed to be made: • Clause 17.2(d) – can be deleted as captured in clause 17.2(b); • Clause 18(e) – reference to Planned Maintenance can be deleted • Clause 18(g) – reference to	DBP submits that this change should be made for the following reasons: • Curtailments are permissible where required to undertake Major Works and Planned Maintenance. Inclusion of Planned Maintenance in the definition streamlines clause 17.2 • Simplify the Access Contract by having a single Notice and planning regime apply for both Major Works and Planned Maintenance;	The consequences of including Planned Maintenance in the definition of Major Works go further than simply streamlining clause 17.2 and introducing a single notice and planning regime. Please see CPMM's comments at item 2.19 below. Since 1995, the DBNGP contracts have had two regimes for outages: planned maintenance (for which outages count toward the 2%

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
			Planned Maintenance can be deleted	• The notice provisions for Major Works in clause 17.6 would then apply to Planned Maintenance so that Operator's obligation is to try to time Planned Maintenance to coincide with Shipper shut downs (if such works would interfere with Shipper's operations);	curtailment threshold) and major works (for which they do not). The separate major works regime was created to allow sporadic major activities such as tying in loops an commissioning new interconnections. It allows DBP more operational latitude, precisely because the intermittent and major nature of these activities both requires and permits such latitude. It's not appropriate for DBP to try to extend that more generous regime to all run-of-the-mill planned maintenance activities, which should be closely managed to minimise harm to shippers.
2.3	Definition of Part Haul	Definitions	Amendment of Part Haul definition to provide: **Part Haul** means *gas transportation service on the DBNGP where the Outlet Point is upstream of Compressor Station 9 on the DBNGP, regardless of the location of the Outlet Point, but does not include Back Haul.*	DBP's submission is that the Part Haul definition in the 2005-2010 Access Contract should be restored. There are a number of reasons for this, as set out in the Access Arrangement submissions, section 3. In summary: • there is no evidence that a significant part of the market for gas transportation services has sought, or will seek, an access contract for a Part Haul service (as that service is defined in the current access arrangement) where the outlet point is downstream of CS • in fact, there has been no requests for this service since it has been available as a reference service. • All shippers who have used the Mondarra Storage facility and who are likely to also deliver gas to an	CPMM has no objection to the proposed amendment.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				outlet point downstream of CS9 have been using their existing T1 contracted capacity. • All potential users of the storage facility and who are likely to also deliver gas to an outlet point downstream of CS9 already have a T1 service access contract and therefore it would not be economic for them to enter into a separate P1 service (given the take or pay tariff obligations under the T1 Service contract) Moreover, the definition of Part Haul service in the current access arrangement: • is confusing; • causes discrimination problems in that potentially deliveries downstream of CS9 could be under a full haul or a part haul contract Accordingly, there is no basis for its inclusion as a reference service.	
2.4	Term – Options to extend term	4.3-4.7	Deletion of options to renew. Consequential Change: Delete definition of Original Capacity	Access contracts for a reference service (where spare capacity exists) are for a minimum term of 2 years. DBP submits it would be inconsistent with the National Gas Objective to provide the shipper with an option to extend a two year term contract because of the following reasons: • DBP would not be able to deal with access requests made by other prospective shippers until all existing shippers have had the opportunity to exercise their options. This will be problematic in circumstances where there is insufficient pipeline capacity	The regime must balance the operator's need to be able to plan future demand and expansions, with shippers' needs to match gas transport capacity to project life. It's true that DBP should not be forced to expand the pipeline to cover the risk of a shipper exercising an option, only to have the option not exercised and DBP being left with surplus capacity. However, this can be avoided by ensuring that the option must be exercised sufficiently far in advance

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				to accommodate the new shipper's request and any extension of the term by existing shippers • In the event that a shipper elects not to exercise its option, DBP and the prospective shipper may have already decided to undertake an expansion of the capacity of the pipeline. Alternatively, the shipper may decide to withdraw its request for access due to the uncertainty about there being spare capacity. Either of these outcomes would be inefficient and send the wrong investment signals. • Furthermore, it is open to shippers with reference service access contracts to apply for a new Access Contract towards the end of their term, in which case, they would be on the same position as all prospective shippers seeking access. It would be inequitable if a party has a when there was spare capacity and a new shipper has little opportunity to access the same transport volume as spare capacity becomes limited. In this case each party should have equal opportunity to access the available capacity.	(say 3 years) to precede the construction start date. As a general observation, the less flexibility built into the reference service terms and conditions, the greater DBP's bargaining power. In theory, matters such as this can be left to be negotiated. In practice, often, anything not prescribed in the regulated terms either will not be accommodated, or will only be accommodated on payment of additional consideration or granting additional benefits to the pipeline operator. In practical terms, almost no shipper has the time or resources to commence an access dispute. As a result access seekers are at a very substantial negotiating disadvantage. The less flexibility that is built into the reference terms and conditions, the greater that disadvantage.
2.5	Refusal to receive gas	5.3(e)	Delete "subject to determination by Operator as a Reasonable & Prudent Person…"	DBP submits that this change should be made on the following bases: • As presently drafted in the Access Contract it is not clear what the Operator is required to determine. The proposed change removes this uncertainty;	CPMM objects to any erosion of a requirement that the Operator must make determinations under the contract as a Reasonable and Prudent Person. There is no credible reason why DBP's behaviour standards should be arbitrarily lowered.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				• A determination by Operator that Shipper has engaged in misconduct or negligence or breach is implicitly required for the Operator to exercise its rights under this clause. If the Operator exercises its rights to refuse Receipt of Gas under this clause in the absence of such act or omission by the Shipper, the Operator would arguably be in breach of contract. • The Operator's main remedy in the event of a shipper's breach or negligence or misconduct is to refuse to Receive Gas. As drafted in the current Access Contract, this clause weakens this right of the Operator by qualifying when it should be able to refuse receipt if there is a breach (including negligence) to enable Operator some power to force Shipper to comply with terms – particularly payment.	The drafting could however be improved. A similar concept is slightly better expressed in the words (proposed to be deleted) at the start of clause 5.7(b), although there too the link between the important first part of the clause and the second part, could be improved. The "Reasonable and Prudent Person" test provides a valuable objective standard for judging DBP's behaviour. DBP should be required to advance cogent reasons consistent with the NGO as to why this standard should be eroded.
2.5A		5.3(g)	delete words		This is definitely not a minor amendment. The effect is to substantially change the balance of priorities at a constrained inlet point. The original words ensured that a shipper with reserved capacity at an inlet point was guaranteed the ability to inject gas up to its contracted capacity. If DBP faced a constraint, it could curtail the shipper and face the consequences. The proposed new wording lets DBP

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					refuse to receive gas from this shipper to give priority to other shippers' interests, and because of clauses 17(3)(b)(iii) and (c)(ii), and clause 17.5, that refusal will not even count towards the 2% curtailment limit. CPMM does not have enough information to judge the full effect of this change, but it is potentially a substantial rearrangement of the priority regime, especially if this change is not replicated in all shippers' contracts.
2.6	Failure to receive where MAOP is exceeded	5.5	Delete cross reference to clause 5.3(d) (exceeding MAOP) as a basis for claiming that a refusal to deliver is a curtailment in certain circumstances.	Clause 5.5 has the effect that if delivery of gas causes the pipeline to exceed MAOP in a situation that would not have happened if the Operator had acted as a R&PP to avoid, then the failure to receive gas is a curtailment. This is not justifiable because: • MAOP is set by the pipeline design, • the Operator is not able to take steps to allow deliveries of gas into the pipeline that would cause it to exceed MAOP, and should be entitled to refuse receipt in that case without risk of penalty.	CPMM object to the proposed change on the basis that the Operator is unlikely to be considered as having failed to act as a RPP in this situation.
2.7	Refusal to Deliver gas	5.7(d) (sic)	Delete "to the extent that the Operator assesses as a Reasonable and Prudent Person that a reduction in Gas Transmission Capacity is required and decides to refuse to Receive Gas …"	Refer to comments in paragraph 2.5 above. These comments are repeated but in relation to Deliveries of Gas rather than Receipt of Gas. The suggested changes are proposed to clarify clause 5.7(d) of the Access Contract and bring into line with corresponding clause 5.3(e) of the Access Contract.	The proposed change is to clause 5.7(b). This change is an attempt by DBP to obtain substantial commercial leverage. At present, the clause, although not well drafted, only permits supply suspension in response to a contractual breach when it is

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					necessary to protect the pipeline's integrity. Supply suspension, and the threat of it, is of course an enormously powerful bargaining tool. The proposed change would allow DBP the ability to use it in all breach circumstances, plus for the undefined and sweeping concept of "misconduct". The ERA is asked to remember that due to the oddities of DBP's contract, refusals to accept or deliver gas operate in parallel to, and are not as well controlled as, the normal curtailment regime, and do not count towards curtailment limits. They thus give DBP extra powers (and the shipper extra uncertainties) not normally found in a gas transmission agreement. The ERA should be slow to allow DBP to further expand this leverage. Operationally, of course, from a shipper's perspective there's no difference between a refusal to accept/deliver, on one hand, and a curtailment, on the other. Either way, the gas does not flow. The two separate regimes date from a conceptual error made in the original GTR contract in 1995. Over the years since 1995, this duplication was slowly wound back, by making refusals to accept or deliver subject to the same accountabilities as curtailments (see

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					eg. clause 5.9, discussed in item 3.16 below). CPMM asks the ERA to be vigilant that DBP does not reverse that trend by making ostensibly "minor" amendments which in fact give it greater leverage.
2.8	Multi-shipper Agreements	6.3(e)	Amend this clause to provide: ~~The Operator must promptly enter into a~~ A Multi-shipper Agreement in respect of an Inlet Point or Outlet Point ~~if~~ is an agreement that contains terms that satisfy all of the following ~~apply to the Multi-shipper Agreement~~: i) if any one of A, B or C apply …..	As drafted this clause did not make sense. It set out that Operator must enter into a Multi-Shipper Agreement if … all of the following apply to a Multi-Shipper Agreement. This seems like drafting error that has been carried through.	CPMM disagree that this is a drafting error and object to the proposed change. The Operator should be required to enter into a Multi-shipper Agreement in this circumstance. The original drafting is certainly inelegant, but it had the effect that if the proposed MSA met the specified standards, DBP must enter into it. DBP proposes to remove that obligation. This has material commercial effect: because an MSA is a pre-condition to receipt or delivery of gas at a multi-shipper point, and moving gas receipts and deliveries to new multi-shipper points is an important risk mitigator for the shipper, because it allows the shipper to mitigate the take or pay risk under its gas sale agreements and gas transportation agreements by finding alternative sources of, or markets for, gas during its or its suppliers' outages. An MSA is largely an agreement between the affected shippers as to how the commingled gas flows will be apportioned, but requires DBP to be a party for operational reasons.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					Removing an obligation on DBP to enter into such an agreement, enables DBP to block the shipper's risk-mitigation efforts, which increases DBP's bargaining power and the risk of DBP extracting additional returns without actually adding extra value.
2.9	Out of Spec Gas	7.8	Insert the words "flare or burn" after "vent" in clauses 7.8(b)(i) and (ii)	Ensure that the Operator can utilise these options if necessary. This reflects the practical operation of the pipeline. Further, it ensures that the Operator can address out of specification gas issues as quickly as possible, given the consequences for the operator under the contract and also the practical consequences for customers downstream if out of specification gas is delivered to outlet points	CPMM has no objection to adding "flare". The addition of "burn" could have broader commercial consequences, because it would include burning the gas in a compressor turbine. CPMM submits that if the gas is good enough to be allowed into the pipeline for use as compressor fuel, then it should not be treated as undelivered under clause 7.8(b)(ii). CPMM also asks the ERA to investigate the interaction between this change, which opens up to DBP a potential occasional source of free gas, and the system use gas provisions and pricing.
2.9A		8.2(a)	removal of "Reasonable and Prudent Person" and other language changes		No explanation is given for this change. CPMM submits that there is no reason not to maintain the same standard of behaviour, to ensure that this clause cannot be abused or become an onerous ongoing pre-nominations regime.
2.10	Imbalance Limit	9.5(c)-(d)	Delete clauses 9.5(c) an 9.5(d)	The notice provisions in clause 9.5(c) and 9.5(d) are not workable in practice. DBP submits that the base reference service	The DBNGP has been operated in accordance with the notice

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				should not give shippers the right to excess imbalance rights above 8% above contracted capacity. DBP management understands that globally, the standard is 2% above contracted capacity. The changes proposed remove notification provisions and provide that once 8% limit is hit, charges for the imbalance automatically apply without the notice provisions (notice to all other shippers etc) applying.	requirements in clause 9.5 for over 10 years and CPMM reject the notion that these provisions are unworkable, particularly in view of the fact that the vast majority of current shippers will not be subject to these amended reference service terms and conditions. If the recontracting shippers enjoy more favourable terms in this respect, shippers who opt for a regulated reference service will face considerable loss of flexibility as a result of these changes. This reduces the value of the reference service and, by degrading the alternative to a negotiated outcome, distorts the contract negotiation process. The Operator is well equipped to assess and deal with the impact of shippers' Accumulated Imbalances in excess of Accumulated Imbalance Limits on any given Gas Day and to notify shippers accordingly, therefore CPMM objects to this proposed change and submits that the notice requirements of clause 9.5 should be reinstated. See also comments at item 2.11 immediately below.
2.11	Obligation to pay Excess Imbalance Charge	9.6(e)	Deleted the words "If the Shipper does not comply…. By the end of the following Gas Day" and "up to the Outer Accumulated Imbalance Limit" and "the Gas Day on which the notice is issued	As per above – simplification of imbalance regime.	The proposed change is to clause 9.5(e). The proposed change may simplify the imbalance regime for the Operator but

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
			and each subsequent Gas Day". So that the clause now just reads: *"The Shipper must pay an Excess Imbalance Charge at the Excess Imbalance Rate for each GJ of Gas in excess of the Shipper's Accumulated Imbalance Limit in accordance with clause 20 in respect of each Gas Day that the absolute value of the Shipper's Accumulated Imbalance exceeds the Shipper's Accumulated Imbalance Limit until the absolute value of the Shipper's Accumulated Imbalance is less than, or closer to the Accumulated Imbalance Limit (as the Operator sees fit)."*		is detrimental to the Shipper. A Shipper may have exceeded its Accumulated Imbalance Limit for reasons outside its control so should have the opportunity to reduce the imbalance before Excess Imbalance Charges are imposed. The two-stage imbalance regime emerged from the arms-length 2004 renegotiations, and provides a more sophisticated balance between the shipper's and the pipeliner's interests than DBP's proposed more blunt instrument. This proposed change increases risk for shippers. DBP should be asked to demonstrate why this erosion of the existing standard terms advances the NGO. The philosophy underlying the two-stage balancing (and peaking and overrun) regime is that the impact of an excursion depends on the prevailing circumstances at the time. Sometimes, the pipeline is in stress, and the shipper must manage its flows carefully to avoid harming other shippers or impacting efficient pipeline operation. But on many occasions the pipeline can tolerate excursions without harm or loss. Imposing too restrictive a regime can unnecessarily reduce shipper flexibility, and hence efficiency, in managing their own gas flows. There is no point requiring a shipper to reduce its plant's output (of electricity,

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					crushed ore, or whatever) in order to comply with an arbitrary limit, in circumstances where that limit can be exceeded without harm. Conversely, if the excursion would cause harm, the shipper can and should be required to comply with the limits. The current two-stage regime, although more complex, implements this balance, and CPMM recommends that it be retained.
2.12	Options for restoring the shippers' imbalance to zero	9.9	In relation to cashing out imbalances at end of Gas Month, new clauses inserted to provide more options regarding restoring the balance to zero. If imbalance is positive, then storage service or Operator buys the gas at the fair market price. If the imbalance is negative, Shipper pays the Operator for the gas at the fair market price or delivers enough gas to the Operator to restore the balance to zero. "Fair market price" is defined as $8 per GJ (in 2015 $).	This allows the parties flexibility to either enter into a storage agreement with DBP for accumulated imbalances or to cash out, depending on what they are paying for gas.	The description at left is inaccurate in that the shipper does not pay a "fair market price", it pays the price DBP has negotiated, regardless of market price. The individual volumes affected by this clause may be small, especially in normal months. But the cumulative effect, and the effect in outlier months, may be substantial. CPMM asks the ERA to model the cash flow impacts of these changes, using historical imbalance data. CPMM submit this is an unreasonable change that will unfairly disadvantage reference service shippers. Furthermore, clause 9.9(b) doesn't specify at whose election positive imbalances are to be dealt with. DBP's "storage service" is unregulated. DBP will be able to charge whatever the market can bear, which may or may not have any connection with

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
					DBP's (often low) cost of service provision. In practical terms, no shipper will have the time or resources to bring an access dispute over the proposed terms for such a service. Hence they will be forced into a take-it-or-leave it outcome on those terms. Imbalances sometimes arise due to factors beyond the shipper's control. Further, shippers' gas contracts will not always contain make-up provisions which allow the shipper to increase volumes to make up shortfalls, especially on cycles as short as a month. The result of all this is that a shipper may be forced into a monthly choice between paying DBP's negotiated gas price, or accepting DBP's unregulated storage service – a choice in which DBP controls the value on both sides of the equation.
2.13	Peaking limits	10.1	Drafting Change only – clarify the definition.	Peaking is limited to 125 % in winter and 120 % in summer. There are no changes to the current peaking limits proposed in the new Access Contract. However, DBP proposes that the contract should be changed so that in the event peaking exceeds these amounts, Hourly Peaking Charge is automatically applicable. Notice provisions are cumbersome and do not work in practice. Peaking notice clauses to be streamlined so that charges apply automatically once limit reached	See comments at item 2.14.
2.14	Rights and obligations of parties when peaking	10.3(a)	Amend to provide that the Operator may (subject to clauses 10.3(e) or	The changes remove the requirement that:	The DBNGP has been operated in accordance with the notice

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
	limits are exceeded		10.3(f), do either or both of: • issue a notice requiring the Shipper to reduce its take of Gas, in which case the Shipper must comply immediately or procure immediate compliance and stop exceeding the Hourly Peaking Limit; or • refuse to Deliver gas to the Shipper at any Outlet Point within the relevant pipeline zone until the Shipper's Hourly Peaking limit is within the Hourly Peaking Limit	• the Operator can only carry out these steps if the peaking will have a material adverse impact on the DBNGP or adversely impact any other capacity or reserved service; and • notice must only require reduction in take of Gas to the extent reasonably required to ameliorate the condition that there is an impact on other Shippers; and Furthermore, they make the requirement on Shipper to reduce the Gas take absolute, not "best endeavours". DBP submits that this is reasonable – the Shipper still has a large degree of flexibility with the allowed peaking limit. There is no justification for allowing the Shipper such greater peaking rights, and further there is no justification for imposing the onus on the Operator to determine whether the Shipper taking more than 20% to 25% above their contracted capacity in an hour will impact on other shippers.	requirements in clause 10 for over 10 years and CPMM reject the notion that these provisions are cumbersome, particularly in view of the fact that the vast majority of current shippers will not be subject to these amended reference service terms and conditions. CPMM object to these proposed changes and submit that the notice requirements of clause 10.3 should be reinstated. CPMM's comments in item 2.10 and 2.11 apply also here. DBP is attempting to shift the risk and flexibility balance in its own favour and against the shipper, without advancing any justification for why this is necessary or consistent with the NGO. CPMM believes that the more sophisticated two stage mechanism should be retained. In response to the final sentence of DBP's note, CPMM would suggest that managing the pipeline to allow all shippers to enjoy their contractual entitlements is DBP's core function.
2.15	Issuing of notices when peaking limits are exceeded	10.3(b) 10.3(c)	Delete	DBP submits that these clauses should be deleted. The requirement to issue notices to all shippers is not workable in practice and is an unreasonable administrative burden on DBP, where the Shipper has already exceeded the hourly take by 20% to 25%. The relevant Shipper is able to access its peaking behaviour through the	Please see CPMM's comment at item 2.14 above.

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				customer reporting system. So, the shipper is able to manage its behaviour with access to sufficient information. It is also likely that the shipper has access to further information in its downstream operations. It should be irrelevant what other Shippers are doing. [	
2.16	Outer Hourly Peaking Limit	10.5	Delete clause 10.5	Clause 10.5 in the current Access Contract allowed for the concept of the Outer Hourly Peaking Limit. This is a penalty type clause whereby if the peaking exceeds 140%, the Shipper is penalised at a higher rate for the entire time that peaking occurs. DBP proposes that this be deleted and the simpler charging regime referred to above is imposed. This is cheaper for the Shipper and much easier for DBP to administer.	The proposed changes to clause 10.3 make the charging regime easier for the Operator to administer but are detrimental to the Shipper. A Shipper may incur Peaking Charges for reasons outside its control. The current regime was negotiated at arms' length and provides a fair balance between the two parties' risk and operational flexibility.
2.17	Overrun	11		Streamlining concept of overrun to remove reference to "authorised" and "unauthorised" overrun. All overrun is unauthorised in the reference service and charges apply.	CPMM's comments in relation to the proposed peaking and balancing changes apply also here. The two-stage overrun regime was an arms-length negotiation to balance the fact that a shipper's overrun can have very different consequences, depending on the circumstances at the time. DBP should be asked to demonstrate why the current balance is inappropriate, and why the proposed changes better meet the NGO. CPMM submits that no change is appropriate.
2.18	Operator's rights in respect of Overrun Gas	11.2	Delete the words "but only to the extent…obligations to Shippers"	The words that DBP proposes to delete in clause 11.2(a) provide that the Operator	This is another example of the Operator seeking to streamline its

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				can only stop overrun gas if: • to the extent that it will impact on another shippers entitlement to its nomination; and • it provides all other shippers with an unavailability notice taking overrun gas in the same zone. DBP submits that overrun gas is gas delivered above the Shippers aggregate contracted capacity. The Operator should be able to cut out overrun gas, as this goes above the contractual entitlements of the shipper under the T1 service. As per above for peaking and imbalances, the notice requirements are administratively onerous and unworkable for DBP. The provision should be streamlined so that it is a meaningful right for DBP to ensure that Shippers do not take more than they are entitled to under their Reference Service contract. Shippers have constant access to CRS information to enable them to monitor and manage their gas flow, and in the event that CRS is not available, the Operator is not entitled to exercise its rights under this clause.	operations to the Shipper's detriment. The comments made above in relation to peaking and balancing also apply here. If overrun will cause harm, it should be prevented. But if the overrun is operationally and commercially harmless, it should be allowed to be corrected without penalty. CPMM objects to these proposed changes and submit that the notice requirements of clause 11.3 should be reinstated.
2.19		17.4	Insert words: "To the extent that curtailment of the Shipper's R1 Service exceeds the T1 Permissible Curtailment Limit for any reason other than … [FM and Operators rights to refuse to receive/deliver gas in cl 5]	Currently, there is no refund to Shipper if the curtailment is due to FM or Operators' rights to refuse to receive/deliver gas under clause 5. This will not change. Currently a refund would apply if a curtailment is due to Major Works, Maintenance or a safety issue (that does not amount to an event of FM). DBP's submission is that for the reference	CPMM acknowledges that the Operator should be entitled to have a certain amount of "down time" each year to carry out maintenance and major works, up to the relevant Permissible Curtailment Limit. However, the Operator's proposed changes do not entitle the Shipper to a refund of the Capacity Reservation

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				service, no refund should apply for curtailments associated with Major Works (including Planned Maintenance) or remedy of a safety issue provided that the relevant curtailment does not exceed the T1 Permissible Curtailment Limit (ie 2% of the time in the relevant Gas Year). DBP submits that: • it should be entitled to have a certain amount of "down time" each year to carry out maintenance and major works, up to a limit that is sufficient time for DBP to carry out the works as a Reasonable & Prudent Person, operating the DBNPG in accordance with Good Gas Industry Practice. This is up to the T1 Permissible Curtailment Limit. • This position is supported by the 98% reliability premise of the DBNGP. • If the time taken for such activities exceeds the T1 Permissible Curtailment Limit, then the refund should apply.	Charge if the time taken for such activities exceeds the relevant Permissible Curtailment Limit. Under clause 17.2(b), the Operator may Curtail the Capacity Services whenever it needs to undertake any Major Works which, by virtue of the Operator's proposed change, also includes Planned Maintenance. Under clause 17.3(c), a Curtailment in the circumstances set out in clause 17.2(b) is not to be aggregated with other Curtailments in determining whether the accumulated duration of Curtailments in a Gas Year cause the relevant Permissible Curtailment Limit to be exceeded. To achieve the objective described in the rationale for change, the reference to clause 17.2(b) should be deleted from clause 17.3(c)(i).
2.20	Tax Changes	20.5	Amend clause 20.5 to include words underlined: (a) the T1 Tariff may be varied for: (i) CPI Changes; (ii) Tax Changes; (iii) New Costs; (iv) Revenue cap adjustments undertaken in accordance with clause 11.5 of the Access Arrangement;	Clause 20.5 refers changes to section 11 of the AA that sets out the Tariff Variation Mechanism and requires that that tariff may only be varied by that mechanism. Currently the Access Contract then restates part but not all of the Tariff Variation Mechanism. DBP proposes to refer to the Tariff Variation Mechanism in the AA in clause 20.5 and remove duplication of this mechanism in the contract. The reasons for doing so include:	"CPI Changes" is not defined in the reference service terms and conditions. Revenue cap adjustments and trailing average cost of debt are covered in the Access Arrangement at clauses 11.6 and 11.7 respectively, rather than at clauses 11.5 and 11.6. The Operator's rationale for this proposed change is to avoid duplication and confusion and prevent changes being made in the Access

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			(v) The annual update of the trailing average cost of debt calculation in accordance with clause 11.6 of the Access Arrangement; and (vi) any other type of cost variation that the Regulator may approve from time to time arising after the date of this Contract, that meet the relevant criteria in the Reference Tariff Variation Mechanism; and (b) the T1 Tariff shall be re-set to reflect any new T1 Tariff approved by the Regulator for any new Access Arrangement Periods over the Term of this Contract. Delete the words "any adjustment of the T1 Tariff during the term of this Contract will be made in accordance with the Reference Tariff Variation Mechanism."	• avoid duplication of part of the AA; • avoid confusion that arises due to only part of the AA being incorporated for variations to the tariff due to Tax Changes; • prevent changes being made in the Access Contract that aren't reflected in the AA, and vice versa; This proposal enables clause 20.7 to be deleted entirely and contains all detailed tax change and new cost variation provisions in one place. Amendments are also proposed to section 11 of the AA to regarding the Tariff Variation Mechanism. Subclauses 20.5(a)(iv) and (v) reflect the new method of setting the tariff proposed by DBP. New sub-clause 20.5(b) has been inserted to ensure that it is clear that if the term of the Contract overlaps a new Access Period, and a new T1 Tariff is set for the reference service, then the new T1 Tariff will apply from the date that the new Access Arrangement period commences. Deletion of the final paragraph is just to avoid duplication - this concept is captured by reference to the requirement that the Reference Tariff Variation Mechanism criteria are met.	Contract that aren't reflected in the AA, and vice versa. However, clause 20.5 introduces some inconsistency in that Carbon Costs are dealt with as a Tax Change in the Access Contract but as a New Cost under clause 11.5 of the AA. The Operator's rationale also refers to the new method of setting the tariff proposed by DBP being reflected in subclauses 20.5(a)(iv) and (v), which subclauses do not exist in the proposed amended Access Contract terms and conditions.
		20.7	Consequential Change: Delete clause 20.7	Refer above. DBP proposes that this is no longer required if the change to clause 20.5 is accepted.	Subject to the eradication of the inconsistencies described in item 2.20 above, CPMM doesn't object to the deletion of clause 20.7.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
		Definitions	*Consequential Change:* ***New Costs*** *means costs arising due to a change in Law and additional costs not included in the forecast operating expenditure that arise from a change in the type or level of fees payable to the Land Access Minister under any Access Right relating to the DBNGP and granted under the Dampier to Bunbury Pipeline Act 1998.*	Definition is taken from clause 11.4(b) of the AA and it is submitted that it be included for the purposes of the changes proposed to clause 20.5	Please see our comment at item 2.20 in regard to Carbon Costs being treated as a New Cost under clause 11.5 of the AA but as a Tax Change under the Access Contract.
		Definitions	Insert into definition of **Tax Change** a further category being*: "any Tax which was in force and validly imposed on the Operator or any of its Related Bodies Corporate as at the commencement of the Current Access Arrangement Period is repealed;"*	This change is suggested to ensure that if a tax is repealed, then the reduction in tax expense is passed through to the Shippers.	CPMM has no objection to this proposed change.
		Definitions	Consequential Change: Delete definition of Tax Change Notice	Term no longer used if DBP's proposal is accepted.	CPMM has no objection to this proposed change.
2.21	Relinquishment rights	26	Deleted	DBP submits that in the Access Contract, the general right of relinquishment should be removed. The term of these contracts are potentially as low as 2 years. There is no call for relinquishment rights in this circumstance. Also, shippers have the right to trade their capacity under clause 27 if for some reason they need less than they have contracted for.	Relinquishment rights should only be deleted if the Operator can offer assurances that flexible Access Contract periods will be offered to prospective shippers seeking access so that they are not locked-in to excessively long contracts for capacity services.
2.22	Non-discrimination	45	DBP proposes that this non-discrimination clause should be deleted Consequential change: Delete definition of Relevant Company. Relevant Company is defined as a direct or indirect shareholder of the Operator or	Clause 45.1 is not required as: • information relevant to the shipper regarding maintenance is provided under the other terms of this contract; • this information is largely available on	CPMM has no in-principle objection to the proposed deletion of this clause. However CPMM asks the ERA to consider whether the revised access arrangement will contain adequate protections:

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			a service provider to the Operator and all Related Bodies Corporate of those entities. This term is not used except in clause 45.	the internet or on the IMO bulletin board; • CRS largely controls information provided to shipper regarding gas flows and this is in a pre-set real time format that all shippers have access to. Clause 45.2 is not required as: • there is no longer any ring fencing requirement between the Operator and its owners as WestNet and Alinta are no longer owners or involved in operation of the DBNGP; • it is accepted that Alcoa as foundation shipper has a different shipper contract to other shippers, and that non-discrimination provisions do not apply to Alcoa; • provisions in the NGL prevent information being provided to a person who is carrying on a related business and prevents entry into associate contracts (ss 140, 147 NGL)	• for shippers on regulated access contracts, as compared with recontracting shippers; and • against favourable treatment for any shipper related to DBP or its owners, to ensure that the NGO is advanced.
3. SUMMARY OF MINOR/DRAFTING CHANGES					
3.1	Definition of Access Request form	Definitions	Simplify definition by referring to form set out in Schedule 1.	Simplify definition, clarify form.	Noted.
3.2	Definition of DBNGP and Kwinana Junction	Definitions	Change 2011-2015 to 2016-2020, and refer to link to ERA website section that sets out the current pipeline description, which link is set out in Schedule 4.	Updates to applicable access arrangement. Reference to Schedule 4 link ensures accurate and current description updates automatically	Noted.
3.3	Definition of Original	Definitions	Delete	Not used. Relates to options to extend	Noted.

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	Capacity			term, which have been removed from this reference service.	
3.4	Definition of Outlet Station	Definitions	Insert underlined: "…and includes gate stations as well as any facilities…"	Include gate stations in definition of outlet station to ensure that costs of maintaining gate stations are included.	Noted.
3.5	Compliance with ring fencing	2.5(e)	Updated references to the current version of the NGL	Update to current legislation reference	Noted.
3.6	Description of T1 Capacity Service	3.2	Amended to mirror SSC T1 contract provisions.	The proposed changes simplify the description, eliminate unnecessary words and bring the description of the T1 Service into line with the Operator's SSC, to prevent confusion about the nature of the service.	Noted but clause 3.2(a)(i) is not a minor drafting change and should be reinstated.
3.7	Term	4.2(b)	Insert the words "specified in the Access Request Form"	Amendment just to clarify and make sense – mirrors words above for Capacity Start Date.	Noted.
3.8	Operator may refuse to receive gas	5.3(g)	Change to delete the words: "to the extent that the Receipt of that Gas for a Gas Day at an Inlet Point is in excess of the aggregate of all of the Shipper's Contracted Capacity in respect of that Inlet Point for that Gas Day," And leave the clause to read: *"if the Operator considers as a Reasonable and Prudent Person that to Receive such Gas would exceed the Shipper's Total Contracted Capacity and would interfere with other shippers' rights to their Contracted Firm Capacity at the relevant Inlet Point."*	Clarification and simplification of clause	This is a substantial change with potentially large commercial consequences. See discussion at 2.5A above.
		5.4(c)	Insert the word "reasonably"	Purpose of change is to make the requirement to provide notice of the	This is an important operational event. It can cause the shipper to incur

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				reasons for refusal to receive gas is provided "as soon as reasonably practicable"	imbalance penalties, and can result in contractual consequences under its gas purchase agreements. The shipper needs to know quickly so it can start making alternative arrangements. DBP gives no reason why the current standard should be degraded. CPMM does not support this proposed change.
3.9	No liability for refusal to receive gas	5.6	Drafting change only – no change in effect.	Clarify the clause. Previously this clause Could be read 2 ways and was ambiguous. Potential for it to be read to mean "when a refusal to receive gas is deemed a curtailment, the operator is not liable for any direct damage…"	Noted.
3.10	Multi-shipper agreement	6.3(a), (b), 6.4	Minor drafting change.	"Multishipper" to "Multi-shipper" throughout – in line with definition in 6.3(d)	Noted.
3.11	Allocation of Gas at Outlet Points	6.5(b), (c)	Minor drafting change.	Minor drafting changes to ensure consistent terminology (Receives Gas, rather than take Delivery of), to avoid confusion and to note that it relevant deliveries are for a Gas Day at any particular Outlet Point.	The change to add the words "at a constant rate over that Gas Day" is not trivial. If DBP, making the determination as a Reasonable and Prudent Person (under line 7 of this clause), has information about the different consumption profiles of the multiple shippers at that point (eg. if one is a constant-rate plant and one a peaking power generator), it should be required to use that information in making its determination, not ignore it.
3.12	Construction Cost and Maintenance Charge	6.12	Delete the reference to Gate Stations.	Consequential amendment due to proposed inclusion of Gate Stations in	Noted.

No.	Topic	Clauses affected	DBP's summary of changes proposed	DBP's stated rationale for Change	CPMM's comments
				definition of Outlet Station.	
3.13	Certain Installations taken to comply; Change of Law	6.16, 7.10	Minor drafting change.	Plain English drafting and clarification purposes	Noted.
3.14	Aggregated T1 Service	8.16	Moved to 8.17	Clause 8.16 and 8.17 swapped around to create a more logical sequence – one follows the other and they were the wrong way around.	Noted.
3.15	Accumulated Imbalance Limit	9.5(a)	Deleted the words "sum of the Shippers…referred to as" and "(including T1…Transaction)"	The remaining words "Shippers Contracted Capacity across all Shipper's Capacity Services" has this meaning, in fewer words.	CPMM asks the ERA to expressly note that, as stated at left, this is simply a drafting tidy-up and there is no intention to remove Spot Capacity from the imbalance limit.
3.16	Curtailment	17.5	Delete reference to clause 5.9	Consequential change due to deletion of clause 5.9 (see above)	The reference to clause 5.9 has not been deleted and CPMM submits it should not be deleted. See comments at item 2.7 – clause 5.9 is a major element in rectifying the long-term structural defect in the DBNGP contracts which created separate and inconsistent regimes for refusal to receive/deliver gas on one hand, and curtailment on the other. The effect on the shipper is the same in either case – no gas flows – and the contract should not leave room for the operator to exploit the structural error to avoid accountability, by characterising a non-receipt or non-delivery as a clause 5 even rather than a clause 17 event. The remedy negotiated over the years is complex and confusing, but

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					commercially important, and clause 5.9 is an important part of that remedy.
3.17	Curtailment	17.9(ii)	Delete reference to Tx Service	Tx Service no longer exists.	Noted.
3.18	Curtailment of spot capacity	17.9(c)(iii)	Delete	This clause provides that Capacity under Spot Transactions that resulted from Daily Bids must be curtailed with the lower priced daily spot bid price being curtailed before the higher priced Daily Spot Bid Price. These definitions and clause 3.5 that related to Spot transactions were removed from the 2010 AA and this clause is no longer relevant – ie how spot capacity is curtailed is irrelevant to the shippers under this contract.	Noted.
3.19	When Shipper can exercise remedy	22.7(b), (c)	Drafting changes only – no substantive change		Noted.
3.20	Charges	25.2(a)	Drafting changes only – no substantive change – correct typo	"charge" should be "charger"	Noted.
3.21	Pipeline Trustees Acknowledgements and Undertakings	25.5(b)	Drafting changes only – no substantive change		Noted.
3.22	Pipeline Trustee Assignment	Old 25.5(f) 25.5(f)	Delete – (assignment by PT requires deed of assumption and assignment) Drafting changes – "disposee" to "disponee"	Old 25.5(f) is already covered by existing 25.4	Noted.
3.23	Confidentiality	definitions 28.3(a), 28.3(b)(iii), (iv) and (v)	Drafting changes only – no substantive change Remove references to WestNet as no longer an owner or Operator of the DBNGP		Noted.

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			Remove WestNet definition		
3.24	Notices – electronic communications	29.3	Amend to include provision for giving notice via email	In line with Electronic Communications Act, and reinforces 29.4(d)	Noted.
4. SUMMARY OF ADDITIONAL CHANGES TO P1 SERVICE					
4.1	GST	20.6	Insert GST clause - as per T1 contract	Inadvertently omitted from current P1 Access Contract.4.2	Noted.
4.2	Remedy of default	22.3, 22.7	Align days to remedy defaults with T1 contract	Inadvertently omitted from current P1 Access Contract.	Noted although CPMM query why the default rectification periods should be different for the Operator and the Shipper.