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

Submitted by DBNGP (WA) Transmission Pty Ltd

14 March 2011

Reprinted 5 May 2011 to incorporate corrigenda notice dated 5 May 2011; and disclosure notice dated 5 May 2011

Economic Regulation Authority
WESTERN AUSTRALIA

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Economic Regulation Authority website at www.erawa.com.au.

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DRAFT DECISION

1. On 1 April 2010, DBNGP (WA) Transmission Pty Ltd (**DBP**) submitted to the Economic Regulation Authority (**Authority**) an access arrangement revision proposal for the Dampier to Bunbury Natural Gas Pipeline (**DBNGP**) for approval by the Authority under the *National Gas Access (Western Australia) Act 2009* (**NGA**).

2. The access arrangement revision proposal was submitted by DBP pursuant to rule 52 of the National Gas Rules (**NGR**) and comprises a proposed revised access arrangement and revised access arrangement information.

3. DBP also made several submissions of supporting information to the Authority shortly after submission of the access arrangement revision proposal and during the course of the Authority's assessment. A full list of submissions made by DBP is provided as Appendix 2 of this draft decision.

4. On 15 April 2010, the Authority published the proposed revised access arrangement and a public version of the revised access arrangement information on its website and issued a notice inviting submissions from interested parties. On 7 May 2010, the Authority published an issues paper to assist interested parties in preparing submissions. The Authority initially established a period for submissions ending on 11 June 2010 but subsequently extended this period to 9 July 2010.[1]

5. Submissions were received from the following parties.
   - Citic Pacific Mining
   - NewGen Power Kwinana Pty Ltd
   - ERM Power Pty Ltd
   - Chevron Australia
   - BP Australia Pty Ltd
   - Wesfarmers Chemicals, Energy & Fertilisers
   - Electricity Generation Corporation (Verve Energy)
   - Synergy
   - BHP Billiton
   - APA Group
   - Alinta Pty Ltd
   - Rio Tinto

[1] Notice of 2 June 2010.

6. Under rule 59 of the NGR, the Authority is required to make a draft decision that indicates whether the Authority is prepared to approve the access arrangement revision proposal as submitted and, if not, the nature of amendments that are required in order to make the proposal acceptable to the Authority. An access arrangement draft decision must include a statement of the reasons for the decision.

7. After considering submissions received from interested parties, the draft decision of the Authority is to not approve the access arrangement revision proposal. The Authority's reasons for not approving the access arrangement revision proposal are set out in this draft decision.

8. Under rule 59(3) of the NGR, the Authority is required to fix a period (**revision period**) within which DBP may, under rule 60, submit additions or other amendments to the access arrangement revisions proposal to address matters raised in this draft decision. The Authority fixes the revision period at five weeks from the date of this draft decision, expiring at 4.00 pm WST on 18 April 2010.

Summary of Required Amendments

Required Amendment 1

The proposed revised access arrangement should be amended to include a full description of the DBNGP to the same level of detail as set out in the access arrangement information.

Required Amendment 2

The proposed revised access arrangement should be amended to remove the proposed R1 Service as a reference service.

Required Amendment 3

The proposed revised access arrangement should be amended to include, as reference services, the T1 Service, P1 Service and B1 Service as described in the current access arrangement.

Required Amendment 4

The proposed revised access arrangement should be amended to include descriptions of the Tp, Tx and Ty Services and any other pipeline services that DBP is making available or will offer during the relevant access arrangement period.

Required Amendment 5

The value of conforming capital expenditure for the 2005 to 2010 access arrangement period must be amended to values as indicated in Table 15 of this draft decision.

Required Amendment 6

The forecast of conforming capital expenditure for the 2011 to 2015 access arrangement period must be amended to values shown in Table 17 of this draft decision.

Required Amendment 7

In relation to Rate of Return, Table 67 of the proposed revised access arrangement should be amended to reflect the values of CAPM and WACC parameters in Table 45 of this Draft Decision

Required Amendment 8

DBP's Proposed Revisions should be amended to adopt a real pre-tax rate of return of 7.16 per cent.

Required Amendment 9

The proposed revised access arrangement should be amended to exclude from total revenue the increment amounts determined under the incentive mechanism that applied in the 2005 to 2010 access arrangement period.

Required Amendment 10

The forecast of operating expenditure for the 2011 to 2015 access arrangement period must be amended to vales as indicated in Table 73 of this draft decision.

Required Amendment 11

The proposed revised access arrangement should be amended to include a statement that services for gas transportation that are other than services in the nature of reference services are rebateable services within the meaning of rule 93(4).

The access arrangement should also include a rebate mechanism that provides for a share of revenue from rebateable services to be rebated to users of services that are in the nature of reference services. The rebate mechanism should provide for the share of revenue to be rebated as:

Value of revenue to be rebated= 0.8 x (R – (C x Q)

where

R is the revenue from the rebateable service ($);

C is the commodity tariff of the full haul, part haul or back haul reference service, as relevant ($/GJ); and

Q is the throughput quantity of the rebateable service.

Required Amendment 12

The proposed revised access arrangement should be amended to specify the reference tariff charges for the T1 reference service for the calendar year 2011 as:

Capacity Reservation Charge: $1.145584/GJ MDQ

Commodity Charge: $0.136310/GJ

The proposed revised access arrangement should be amended to provide for determination of the corresponding reference tariff charges for the P1 and B1 reference services for the calendar year 2011 as:

Reference tariff charge = F × D/1399

Required Amendment 13

The proposed revised access arrangement should be amended to change the definition of CPI in the reference tariff variation mechanism to "CPI means the Consumer Price Index, All Groups, Eight Capital Cities.

Required Amendment 14

The proposed revised access arrangement should be amended so that the variation of reference tariffs by way of a Tax Changes Variation:

- is limited to costs of tax changes that satisfy the criteria governing operating expenditure set out in rule 91 of the NGR; and
- is subject to the Authority's approval of the variation.

Required Amendment 15

The proposed revised access arrangement should be amended to remove provision under the reference tariff variation mechanism for the variation of reference tariffs by way of a "new costs pass through variation".

Required Amendment 16

The term "B1 Service", under clause 1 of the proposed revised terms and conditions should be amended to be the B1 Service described as a reference service in the access arrangement, amended as required by this draft decision.

Required Amendment 17

The term "Capital Cost of the Expansion" and the definition of this term should be deleted from clause 1 of the proposed revised terms and conditions.

Required Amendment 18

Clause 1 of the proposed revised terms and conditions should be amended to include the term "Contracted Firm Capacity" with the same meaning as the term "Contracted Firm Capacity" in the existing terms and conditions.

Required Amendment 19

The term "Major Works", under clause 1 of the proposed revised terms and conditions should be amended to exclude planned maintenance.

Required Amendment 20

Clause 1 of the proposed revised terms and conditions should be amended to include the term "Overrun Gas" with the same meaning as the term "Overrun Gas" in the existing terms and conditions for the T1 Service.

Required Amendment 21

Clause 1 of the proposed revised terms and conditions should be amended to include the term *"Accurate"* which means *"with respect to any measurement of a quantity of Gas, that the measurement is inaccurate to a lesser extent than the relevant limit prescribed by clause 15.13(a)(i) or 15.13(a)(ii), as the case may be"*.

Required Amendment 22

The terms “Related Body Corporate” and “Related Entity”, under clause 1 of the proposed revised terms and conditions should be amended so as they apply to the definitions in the Corporations Act as defined from time-to-time, and not as limited to a point in time.

Required Amendment 23

The term “Retail Market Rules”, under clause 1 of the proposed revised terms and conditions should be amended to mean *“the retail market rules that govern the retail gas market in Western Australia”*.

Required Amendment 24

Clause 1 of the proposed revised terms and conditions should be amended to have the same meaning as the term “T1 Service” in the existing terms and conditions.

Required Amendment 25

The term “Tp Service”, under clause 1 of the proposed revised terms and conditions should be amended to identify the characteristics of the service.

Required Amendment 26

Clause 2.5(e) should be amended to make reference to *“Part 2 of Chapter 4 of the National Gas Access (Western Australia) Law”* instead of “section 4 of National Third Party Access Rules for Natural Gas Pipeline Systems”.

Required Amendment 27

The proposed revised terms and conditions should be amended to delete clause 2.6.

Required Amendment 28

Clause 2.7 of the proposed revised terms and conditions, in relation to the access regime and the regulator’s requirements as laws should be amended to insert a full stop after ‘Contract’ in the 3rd line and delete the balance of the clause.

Required Amendment 29

Clause 3.2 of the proposed revised terms and conditions should be amended to be materially the same as clause 2 of the current terms and conditions for the T1 Service.

Required Amendment 30

Clause 4.1(a) of proposed revised terms and conditions in relation to the capacity start date, should be amended to include the words “as the Requested Reference Service Start Date" at the end of the sentence.

The definition of “Access Request Form” in clause 1 of the proposed revised terms and conditions be amended to read “means the access request form in the form set out in Schedule 1 entered into between the Operator and the Shipper to which these Terms and Conditions are appended”.

Required Amendment 31

Clause 4.2(b) of the proposed revised terms and conditions, in relation to the term (duration of the contract), should be amended to include the words "as the Requested Reference Service End Date" at the end of the sentence.

Required Amendment 32

Clause 4.5 of the proposed revised terms and conditions, in relation to a shipper exercising an option to renew its contract, should be amended to state “not later than 12 months before the capacity end date, a shipper may give written notice to the operator that it wishes to exercise an option”.

Required Amendment 33

Clause 5.2(b) should be amended to require DBP to deliver gas at the nominated outlet points in the quantities required by the shipper at each point, up to a maximum across all points of the shipper's contracted capacity.

Required Amendment 34

- Clause 5.3(e) of the proposed revised terms and conditions should be deleted. Clause 17.2(c) of the existing terms and conditions should be reinstated.
- Clause 5.3(g) of the proposed revised terms and conditions, in relation to being able to refuse to receive gas, should be amended to read ”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; if the Operator considers as a Reasonable and Prudent Person that to Receive such Gas would interfere with other shippers' rights to their Contracted Firm Capacity “.

Required Amendment 35

Clause 5.4(c) of the proposed revised terms and conditions should be amended to include the words “as soon as practicable’” in relation to DBP providing a shipper with its reasons to refuse to receive gas.

Required Amendment 36

Clause 5 of the proposed revised terms and conditions should be amended to include terms and conditions that are materially the same as clause 5.5 and 5.9 of the existing terms and conditions for the T1 Service, which relates to refusal to receive or deliver gas as a curtailment in limited circumstances.

Required Amendment 37

Clause 5.6(b) of the proposed revised terms and conditions, which provides that the operator may refuse to deliver gas in response to a reduction in gas transmission capacity by reason of, or in response to, a reduction in gas transmission capacity caused by the negligence, breach of contractual term or other misconduct of the shipper, should be deleted.

Required Amendment 38

Clause 5.9 of the proposed revised terms and conditions, in relation to no change in contracted capacity, should be amended to:

- include provisions that are materially the same as those in clause 5.9 of the existing terms and conditions where the refusal to deliver gas is a curtailment in certain circumstances; and
- be amended to reflect situations where the capacity reservation charge must be refunded under clause 17.4 for a refusal to deliver gas.

Required Amendment 39

Clause 5.10 of the proposed revised terms and conditions, in relation to system use gas, should be amended to:

- delete the proposed sub-clauses 5.10(a) and (b) and replace these with a clause to the effect that the operator will provide such system use gas as is reasonably necessary to provide the service; and
- delete the proposed clauses 5.10(c) to (h).

Required Amendment 40

Clause 5.12 of the proposed revised terms and conditions, in relation to shipper's gas installations, should be amended from it being mandatory for a shipper, at its cost, to inspect its facilities to ensure it complies with applicable legislation to it being at the request of DBP acting reasonably.

Required Amendment 41

Clause 6.4 of the proposed revised terms and conditions in relation to allocation of gas at inlet points should be amended to include provisions that are substantially the same as those in clause 6.4(c) and (d) of the existing terms and conditions.

Required Amendment 42

Clause 6.7 should be amended by inserting the words "Subject to clause 6.13" at the commencement of the second sentence in clause 6.7(a).

Clause 6.7(d) should be amended to refer to an outlet, not inlet, station.

Required Amendment 43

Clause 6.8(a) should be amended by:

- inserting the words "Subject to clause 6.13" at the commencement of the second sentence; and
- 6.8(a)(i) reading 'to pay the costs reasonably incurred by the Operator in accordance with good industry practice…"

Required Amendment 44

Clause 6.10(c) about notional gate point should be amended to replace "absolute" with "reasonable" and to insert "in accordance with good industry practice" after "discretion".

Required Amendment 45

Clause 6.12(a) should be amended to:

- include a mechanism to enable a shipper to ensure that only necessary refurbishments and upgrades are carried out;
- include a provision allowing a shipper to obtain a breakdown of the maintenance charge; and
- replace the words "pay a charge for substantially the same purpose" with "use the inlet station, outlet station or gate station associated with a sub-network" and by deleting sub-clauses (iii) and (iv).

Required Amendment 46

Clause 7.2 of the proposed revised terms and conditions, in relation to the requirement for gas to be free from certain substances, should be amended to include the word “reasonably” between the words “as” and “determined by the operator”.

Required Amendment 47

Clause 7.4(c) of the proposed revised terms and conditions, in relation to gas temperature and pressure, should amend the words “receive gas” to “receives gas”.

Required Amendment 48

Clause 7.9(b) of the proposed revised terms and conditions, in relation to the shipper being able to receive out-of-specification gas, should be amended to add the words “by delivering out-of-specification gas to the inlet point” after the words “to be out-of-specification gas”.

Required Amendment 49

Clause 8.9 of the proposed revised terms and conditions, in relation to the scheduling of daily nominations, should be amended to replace references to a R1 Service with references to a T1 Service.

Required Amendment 50

Clause 8.10 of the proposed revised terms and conditions, in relation to scheduling where there is insufficient available capacity, should be amended by inserting a new clause 8.10(c) to read “the operator shall use its best endeavours to minimise the extent of any curtailment required under clause 8.10(b)”.

Required Amendment 51

Clause 8 of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clauses 8.15 and 8.16 in the existing terms and conditions in relation to an aggregated T1 service; and nominations at inlet points and outlet points where a shipper does not have sufficient contracted capacity.

Required Amendment 52

Clause 8 of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clauses 8.16 in the 2005 to 2010 terms and conditions in relation to full haul capacity upstream of CS9.

Required Amendment 53

Clause 9 of the of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clause 9.5 of the existing terms and conditions in relation to accumulated imbalance limit.

Required Amendment 54

Clause 9.6(c) of the proposed revised terms and conditions, in relation to balancing in particular circumstances, should be amended to remove the requirement that the agreement be in writing.

Required Amendment 55

Clause 9.6 of the proposed revised terms and conditions, in relation to cashing out imbalances at the end of each gas month, should be amended to be substantially consistent with the existing terms and conditions.

Required Amendment 56

Clause 10.3 of the proposed revised terms and conditions, in relation to consequences of exceeding hourly peaking limits, should be amended to be substantially consistent with clause 10.3 of the existing terms and conditions and the words “shipper must use best endeavours to comply with a notice issued under clause 10.3” reinstated.

Required Amendment 57

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 10.4 of the existing terms and conditions in relation to outer hourly peaking limit.

Required Amendment 58

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 10.7 of the existing terms and conditions in relation to permissible peaking excursion.

Required Amendment 59

The proposed terms and conditions should contain provisions that are substantially consistent with clause 11.1 of the existing terms and conditions in relation to the overrun charge.

Required Amendment 60

The proposed terms and conditions should contain provisions that are substantially consistent with clause 11.2 of the existing terms and conditions in relation to an unavailability notice.

Required Amendment 61

Clause 11.7(c) of the proposed terms and conditions, in relation to savings and damages, should be amended to reinstate the word “not”.

Required Amendment 62

The proposed revised terms and conditions should be amended to include a provision that is substantially the same as clause 12.4(b) of the existing terms and conditions, in relation to the delivery of gas Clause 12 should therefore provide that the operator may satisfy its obligation to enable gas to be delivered to the shipper by using any means other than the DBNGP provided that it otherwise meets its obligations under the contract and only where there is no extra cost or risk to shipper in doing so.

Required Amendment 63

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 14.2(d)(i) of the existing terms and conditions in relation to the assessment of requested relocation of contracted capacity.

Required Amendment 64

Clause 15.3 of the proposed revised terms and conditions, in relation to metering uncertainty, should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 65

Clause 15.4(a)(i)(c) of the proposed revised terms and conditions should be amended to insert the word “reasonable” after the words “any information”.

Required Amendment 66

Clause 15.5 of the proposed revised terms and conditions, in relation to the provision of information to shippers, should be amended to reinstate sub-clauses (e), (f) and (g).

Required Amendment 67

Clause 17.2, in relation to curtailment generally, should be amended to reinstate sub-clauses (c) and (d) in the existing terms and conditions.

Required Amendment 68

Clause 17.3(b) of the proposed revised terms and conditions, in relation to curtailment without liability, should be amended to be substantially the same terms as clause 17.3(b) in the existing terms and conditions.

Required Amendment 69

Clause 17.5 of the proposed revised terms and conditions, in relation to the operator’s right to refuse to receive to deliver gas, should be amended so that the words “Subject to clauses 5.5 and 5.9,…” are reinstated at the beginning of clause 17.5.

Required Amendment 70

Clause 17.6(b)(ii)(A) of the proposed revised terms and conditions should be amended to insert after the word “must” the words “use its best endeavours to” and after the word “Notice”, the words “a reasonable period in advance of the stating time of the curtailment but in any event”.

Required Amendment 71

Clause 17.7(b) of the proposed revised terms and conditions, in relation to the content of a curtailment notice and initial notice, should be amended to require an initial notice to specify the operator’s reasons for, and a description of, the major works that has initiated the need for an initial notice to be issued under clause 17.6(b)(i)(A).

Required Amendment 72

Clause 17.8 of the proposed revised terms and conditions, in relation to compliance with a curtailment notice, should be amended to be substantially the same as clause 17.8 of the existing terms and conditions.

Required Amendment 73

Clause 17.9 of the proposed revised terms and conditions, in relation to priority of curtailment, should be amended to be substantially the same as clause 17.9 of the existing terms and conditions.

Required Amendment 74

Clause 17.10 of the proposed revised terms and conditions, in relation to the apportionment of a shipper's curtailments should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions and an additional requirement for DBP to notify the shipper of apportionment as soon as practicable after the end of the relevant gas day be included.

Required Amendment 75

Clause 18 of the proposed revised terms and conditions, in relation to maintenance and major works should be amended as follows.

- Clause 18(d) should be amended to insert "17.6(b)(i)(A)" after "clauses".
- Clause 18 should be amended to include terms that are substantially the same as clause 18(e) of the 2005 to 2010 terms and conditions for the T1 Service, requiring the operator to notify the shipper of changes to its schedule of major works and planned maintenance issued to shippers under clause 18(c) of the terms and conditions.

Required Amendment 76

Clause 20.4 of the proposed revised terms and conditions, in relation to other charges, should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions and to include a provision for all of the other charges to be rebateable to shippers.

Required Amendment 77

Clause 20.5 of the proposed revised terms and conditions should be amended to be consistent with the structure of the reference tariff and reference tariff variation mechanism of the proposed revised access arrangement as required to be amended under this draft decision.

Required Amendment 78

Clause 20.7 of the existing terms and conditions, in relation to other taxes, should be reinstated into the proposed terms and conditions.

Required Amendment 79

Clauses 21.4 and 21.6 of the proposed revised terms and conditions should be amended to remove the words "and compounded" in relation to the interest payable for a default in payment or correction of payment errors by a shipper.

Required Amendment 80

Clause 22.3 of the proposed revised terms and conditions, in relation when the operator may exercise a remedy, should be amended to replace the reference to "20 Working Days" with a reference to "40 Working Days".

Required Amendment 81

Clause 22.9 of the proposed revised terms and conditions, in relation to no indirect damages, should be deleted.

Required Amendment 82

Clauses 23.6 and 23.7 of the proposed revised terms and conditions, which establish the shipper's and operator's responsibility for contractors' personnel and property respectively, should be amended to reinstate the liability for death or injury to a party's personnel or damage to a party's property.

Required Amendment 83

Clause 25.1 should be amended to read: *"Subject to this clause 25 and clause 27, neither Party may assign any right, interest or obligation under this Contract"*.

Required Amendment 84

Clause 25.2(a) should be amended to include terms that are substantially the same as clause 25.2(a) of the 2005 to 2010 terms and conditions for the T1 Service, requiring the form of tripartite deed to be annexed in a schedule to the terms and conditions.

Required Amendment 85

Clause 25.3 of the proposed revised terms and conditions, in relation to assignment, should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 86

Clause 25.4 of the proposed revised terms and conditions, in relation to a deed of assumption, should be amended to be substantially consistent with the existing terms and conditions.

Required Amendment 87

Clause 25 the proposed revised terms and conditions should be amended to include terms and conditions that are substantially the same as clauses 25.5 and 25.6 of the existing terms and conditions for the T1 Service, which set out the acknowledgements and undertakings of the Pipeline Trustee and DBNGP Trustee respectively.

Required Amendment 88

Clause 25.6 of the proposed revised terms and conditions should be amended to include terms and conditions substantially the same as clause 25.6 of the existing terms and conditions.

Required Amendment 89

Clause 26 of the proposed revised terms and conditions should be amended to be substantially the same as clause 26 of the 2005 to 2010 terms and conditions for the T1 Service, which establishes terms for a general right of relinquishment by a shipper.

Required Amendment 90

Clause 27.4 of the proposed revised terms and conditions, in relation to transfer of capacity, should be amended to be substantially consistent with the existing terms and conditions.

Required Amendment 91

Clause 28.2 of the proposed revised terms and conditions should be amended as follows:

- Clause 28.2(j) should be amended so that the exception to confidentiality, where the information is requested by an operator of a pipeline which is interconnected with the

DBNGP, is subject to the confidential information being relevant to and necessary for the operation of the interconnected pipeline.

Required Amendment 92

Clause 28.3 of the proposed revised terms and conditions, in relation to permitted disclosure, should be amended to expressly incorporate the operator's obligations to comply with ring fencing provisions under the NGL and NGR

Required Amendment 93

Clause 30.1 of the proposed revised terms and conditions, in relation to operator's representations and warranties, should be amended to be substantially consistent with the existing terms and conditions.

Required Amendment 94

Clause 30.2 of the proposed revised terms and conditions, in relation to operator's representations and warranties, should be amended to be substantially consistent with the existing terms and conditions.

Required Amendment 95

Clause 30 the proposed revised terms and conditions, in relation to representations and warranties of the DBNGP Trustee to a shipper, should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 96

Clause 31 of the proposed revised terms and conditions, in relation to the preparation and maintenance of records and information, should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 97

Clause 38 of the proposed revised terms and conditions, in relation to revocation, substitution and amendment, should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 98

Clause 45 of the proposed revised terms and conditions should be amended to be substantially the same as clause 45 of the existing terms and conditions, which establish terms for non-discrimination.

Required Amendment 99

Schedule 2 of the proposed revised terms and conditions should be amended to detail:

- the "T1 capacity reservation tariff" and "T1 commodity tariff", as determined under this draft decision; and
- the rates at which other charges are determined under the proposed terms and conditions, being the:

– "excess imbalance charge" at 200 per cent of the T1 reference tariff;

– "hourly peaking charge" at 200% of the T1 reference tariff;

– "overrun charge" at the rate specified in clause 11.1(b); and

– "unavailable overrun charge" at the greater of:

- 250% of the T1 reference tariff; and
- the highest price bid for spot capacity that was accepted for that gas day, other than when the highest price bid was not a bona fide bid, in which case the highest bona fide bid.

Required Amendment 100

Schedule 3 in relation to Operating Specifications should be amended to:

- delete the table at item 1 – Gas Specifications, and instead provide that the Operating Specifications are those as specified in the Gas Supply (Gas Quality Specifications) Regulations 2010; and
- amend Item 2 – Gas Temperature and Pressure so that it is the one measurement applying to all inlet points.

Required Amendment 101

Schedule 4 of the proposed revised terms and conditions should be amended to include the pipeline description that is referenced in and appended to the proposed revised access arrangement.

Required Amendment 102

Schedule 6 of the proposed revised terms and conditions, which sets out the curtailment plan, should be amended to be substantially consistent with Schedule 8 of the 2005 to 2010 terms and conditions for the T1 Service.

Required Amendment 103

The proposed revised access arrangement should be amended to include a Schedule 7 that sets out the form of the tripartite deed that is entered into under clause 25.2 of the contract.

Required Amendment 104

The proposed revised access arrangement should be amended to include terms and conditions for the part haul service (i.e. the P1 Service) and back haul service (i.e. the B1 Service), as reference services, that are substantially the same as the terms and conditions established under existing contracts for part haul and back haul pipeline services negotiated with shippers.

Required Amendment 105

Cause 5.3(d) of the proposed revised access arrangement should be amended to include the option for a user to choose between a non-refundable deposit for the submission of an access request or an executed application form.

Required Amendment 106

Cause 5.4(g) of the proposed revised access arrangement dealing with the processing of access requests in the queue, should be amended to include explicit bypass provisions to allow applications in the queue for haulage services that do not require developable capacity to be processed ahead of applications that do.

Required Amendment 107

Clause 7.1 of the proposed revised access arrangement, which sets out a series of tests that must be satisfied before DBP will expand the capacity of the pipeline, should be deleted.

Required Amendment 108

Clause 7.4(f) of the proposed revised access arrangement, extensions and expansion requirements, should be amended by deleting clause 7.4(f). This clause provides that in considering whether to treat the extension or expansion as part of the covered pipeline the operator may have regard to the extent to which capacity is a result of an expansion to be undertaken through the application of the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)*.

Required Amendment 109

Clause 8.2(c) of the proposed revised access arrangement should make reference to section 14 (Relocation) of the access contract terms and conditions not section 13 (Control, Possession and Title of Gas).

REASONS

Introduction

Regulatory Framework

9. The purpose of an access arrangement for a gas pipeline is to provide details of the terms and conditions, including price, upon which an independent third party (user) can gain access to the pipeline.

10. The requirements for an access arrangement are established by the *National Gas Law* (**NGL**) and *National Gas Rules* (**NGR**) as enacted by the *National Gas (South Australia) Act 2008* and as implemented in Western Australia by the *National Gas Access (WA) Act 2009* as the *National Gas Access (Western Australian) Law* (**NGL(WA)).**

11. The NGL and NGR replace the previous national Gas Pipeline Access Law, and National Third Party Access Code for Natural Gas Pipeline Systems (**Gas Code**), implemented in Western Australia by the *Gas Pipeline Access (WA) Act 1998*.

12. Section 23 of the NGL(WA) sets out the national gas objective. Under rule 100 of the NGR all provisions of an access arrangement are required to be consistent with the national gas objective.

> 23. National gas objective
>
> The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

13. Sections 28(1) and (2) of the NGL(WA) specify the manner in which the Authority must perform or exercise its economic regulatory functions or powers.

> 28. Manner in which [ERA] must perform or exercise [ERA] economic regulatory functions or powers
>
> (1) The [ERA] must, in performing or exercising an [ERA] economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national gas objective.
>
> (2) In addition, the [ERA]—
>
> (a) must take into account the revenue and pricing principles—

(i) when exercising a discretion in approving or making those parts of an access arrangement relating to a reference tariff; or

(ii) when making an access determination relating to a rate or charge for a pipeline service; and

(b) may take into account the revenue and pricing principles when performing or exercising any other [ERA] economic regulatory function or power, if the [ERA] considers it appropriate to do so.

Special Circumstances of the Dampier to Bunbury Natural Gas Pipeline

14. Access contracts between DBP and users of the DBNGP – the DBNGP shipper contracts – are currently substantially independent of the access terms and reference tariffs under the access arrangement for the DBNGP. With the exception of an access contract with one user (Alcoa), the current shipper contracts with the major users take the form of the "standard shipper contract" (**SSC**) that was negotiated between DBP and major users in 2004. The standard shipper contract is published on DBP's website.[2]

15. Clause 20.5 (sub clauses (d) to (g)) of the standard shipper contract makes provision for gas transmission tariffs to transition to a reference tariff under the access arrangement in 2016:

(d) With effect from 08:00 hours on 1 January 2016, the Base T1 Tariff must be adjusted so that the Base T1 Tariff, T1 Capacity Reservation Tariff and T1 Commodity Tariff is at any time the same as the Firm Service Reference Tariff (or equivalent) at that time.

(e) In this clause 20.5, Firm Service Reference Tariff means the Reference Tariff for the Reference Service under the Access Arrangement that is, at 100% load factor, the closest equivalent Full-Haul Service to the T1 Service as at 1 January 2016 (T1 Equivalent Reference Service).

(f) The Parties agree the following in relation to the Reference Tariff:

(i) the present intention of the Parties is that, with effect from 08:00 hours on 1 January 2016, the tariff payable by the Shipper under clause 20.5(d) will be a Reference Tariff based on the Reference Tariff Policy in clause 7 of the Access Arrangement as that clause was in force at 27 October 2004 (for the purposes of which that clause 7 is to be read as though references to "Firm Services" were replaced with "T1 Service");

(ii) the diagram and the financial model assumptions in Schedule 9, being the forecast tariff post 2016, illustrate the Parties' current expectations as to the effect of clause 20.5(f)(i). The Parties agree that the tariff levels depicted in Schedule 9 are based on certain assumptions about the inputs and methodology for determining tariffs under the approach approved by the ERA in the Reference Tariff Policy referred to in clause 20.5(f)(i), and that the actual tariff levels payable under clause 20.5(d) may differ from the tariff

2 http://www.dbp.net.au/Libraries/Customer_Access_and_Information/22_09_08_-_Full_Haul_T1_Standard_Shipper_Contract.pdf

levels shown in Schedule 9 if the inputs and methodology are different at 2016. The Parties acknowledge that this clause 20.5 and Schedule 9 may be provided to the Regulator in making any submission referred to in clause 20.5(f)(iii) or clause 20.5(f)(iv).

(iii) Subject to clause 20.5(f)(v), the Operator agrees as soon as it considers is appropriate after 27 October 2004 to endeavour as a Reasonable and Prudent Person to have the Regulator approve amendments to the Access Arrangement that have the following outcomes (and the Shipper agrees to support those amendments (provided such amendments are not inconsistent with the intention of the Parties as at the date of this Contract in respect of the Firm Service Reference Tariff as of 1 January 2016, as reflected by Schedule 9) if necessary by making written submissions to the Regulator):

A. the Full Haul T1 Service to be included as a Reference Service;

B. the Base T1 Tariff as adjusted under clauses 20.5(b) and 20.5(c) to be the Reference Tariff for the Reference Service referred to in clause 20.5(f)(iii)A for the periods identified in clauses 20.5(b) and 20.5(c); and

C. the capacity reservation charge/commodity charge split (i.e. fixed/variable charge split) for the Reference Tariff referred to in clause 20.5(f)(iii)B to be 80%/20%.

(iv) Subject to clause 20.5(f)(v), the Parties must not make any submission to the Regulator which is inconsistent with the following outcomes:

A. the tariff described in clause 20.5(f)(i) becoming the Reference Tariff for the Reference Service described in clause 20.5(f)(iii)A from 1 January 2016; and

B. the capacity reservation charge/commodity charge split (i.e. fixed/variable charge split) for the Reference Tariff referred to in clause 20.5(f)(iv)A to be 80%/20%.

(v) The Parties agree that should the regulatory methodology for calculation of the Reference Tariff assumed in Schedule 9 be one that is considered by the Regulator not to be appropriate for use on the DBNGP from 1 January 2016 or is not consistent with pipeline regulatory practice within Australia, the Parties will endeavour as Reasonable and Prudent Persons to work together to achieve a tariff path outcome which as close as possible delivers the outcomes described in clause 20.5(f)(ii). However, the Parties agree that nothing in this clause 20.5(f), requires the Parties to make a submission which:

A. means the Operator is unable to recoup its full operating and capital costs to the full extent permitted by the Gas Access Code in Schedule 2 to the Access Regime (Code);

B. means the return on capital (debt and equity) to the Operator is outside the range permitted by the Code having regard to reasonable market requirements, including those deemed by the relevant Regulator as being reasonable, at the relevant point in time;

C. means the Operator is unable to perform any of its obligations under the Alcoa Exempt Contract; or

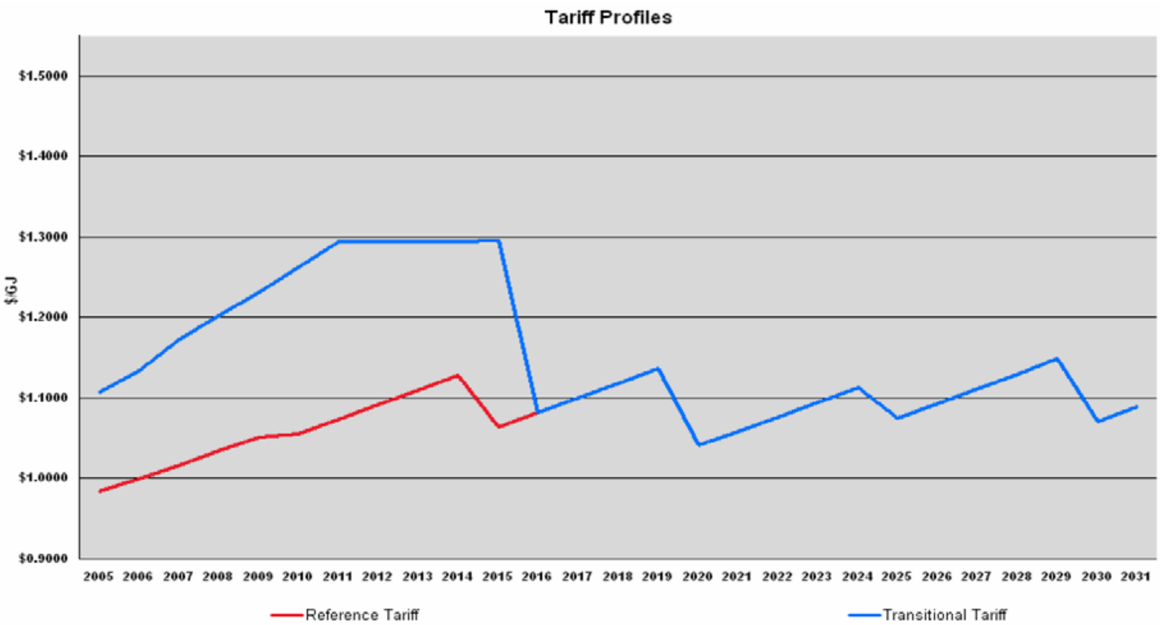
D. is otherwise inconsistent with the provisions of the Code; and

(vi) the Parties intend this clause 20.5 to have effect as a contractual right for the purposes of clauses 2.47 and, if applicable, 6.18(c) of the Gas Access Code in Schedule 2 to the Access Regime.

(g) If on 1 January 2016, and during any time thereafter, the capacity reservation charge/commodity charge split (i.e. fixed/variable charge split) is not 80%/20% of the Firm Service Reference Tariff, the capacity reservation charge/commodity charge split of the Base T1 Tariff will be the same percentage split as the Firm Service Reference Tariff at and during that time.

16. As indicated in sub-clause 20.5(f)(ii) of the standard shipper contract, Schedule 9 of the standard shipper contract illustrates the expectations of the parties as to the time profile of pipeline tariffs, with the contract tariff being in excess of the reference tariff for the period to 2016 and thereafter decreasing to the value of the reference tariff (Figure 1).

Figure 1: Tariff expectations set out under Schedule 9 of the Standard Shipper Contract[3]



3 http://www.dbp.net.au/Libraries/Customer_Access_and_Information/22_09_08_-_Full_Haul_T1_Standard_Shipper_Contract.pdf, Schedule 9

17. As a result of the contractual arrangements between DBP and users, the proposed revised access arrangement may not significantly affect users during the course of the 2011 to 2015 access arrangement period. However, parameters of this revised access arrangement will affect the starting point for the subsequent access arrangement, including the approved building-block components that determine the total revenue requirement and reference tariffs.

18. In submissions to the Authority on the proposed revised access arrangement, some parties contend that the link between the standard shipper contract and the access arrangement is explicit and needs to be maintained to ensure the transition in 2016 to reference tariffs. It is submitted that the link is critical to the re-commercialisation and ongoing investment in the DBNGP and users have paid a premium over and above the reference tariff to ensure this. The link needs to be maintained and to do otherwise would be inconsistent with section 23 (the national gas objective) and section 321 (protection of certain pre-existing contractual rights) of the NGL.[4]

19. In response to these submissions, DBP has submitted that:

- there are no contractual obligations owed by DBP in the standard shipper contract to include anything in the access arrangement at any point in time unless DBP considers this appropriate;
- the standard shipper contract envisages the possibility of future changes and therefore that reference services and tariffs may differ due to different inputs and methodology; and
- the standard shipper contracts do not bind the Authority in any way to make certain decisions in relation to the access arrangement.[5]

20. The Authority considers that the existence and terms of the standard shipper contract do not have a direct bearing on the access arrangement for the DBP. However, the Authority has had regard to the terms of the standard shipper contract as evidence relevant to the Authority's assessment of some elements of the proposed revised access arrangement, such as the demand for certain pipeline services.

Content of an Access Arrangement

21. Under section 2 of the NGL(WA), a "full access arrangement" means an access arrangement that:

- provides for price or revenue regulation as required by the NGR; and
- deals with all other matters for which the NGR require provisions to be made in an access arrangement.

22. The required content of a full access arrangement proposal is specified in rule 48 of the NGR.

4 Alinta Pty Ltd, submission of 9 July 2010; Verve Energy, submission of 9 July 2010.

5 DBP, Submission #26.

48 Requirements for full access arrangement (and full access arrangement proposal)

(1) A full access arrangement must:

(a) identify the pipeline to which the access arrangement relates and include a reference to a website at which a description of the pipeline can be inspected; and

(b) describe the pipeline services the service provider proposes to offer to provide by means of the pipeline; and

(c) specify the reference services; and

(d) specify for each reference service:

(i) the reference tariff; and

(ii) the other terms and conditions on which the reference service will be provided; and

(e) if the access arrangement is to contain queuing requirements – set out the queuing requirements; and

(f) set out the capacity trading requirements; and

(g) set out the extension and expansion requirements; and

(h) state the terms and conditions for changing receipt and delivery points; and

(i) if there is to be a review submission date – state the review submission date and the revision commencement date; and

(j) if there is to be an expiry date – state the expiry date.

(2) This rule extends to an access arrangement proposal consisting of a proposed full access arrangement.

23. When submitting a full access arrangement proposal, the service provider must also submit access arrangement information (rule 43). Access arrangement information is information that is reasonably necessary for users to understand the background to the access arrangement, and the basis and derivation of various elements of the access arrangement (rule 42).

24. The DBNGP access arrangement is a full access arrangement, for which a proposed revised access arrangement and a revised access arrangement information have been submitted by DBP. The reasons for the Authority's draft decision address elements of DBP's access arrangement revision proposal in the following order.

- A description of the pipeline.
- Pipeline services, including the specification of reference services.
- Total revenue requirements.
- Reference tariffs.
- Non-tariff components.

Pipeline Description

Regulatory Requirements

25. Rule 48(1)(a) of the NGR requires an access arrangement proposal to identify the pipeline to which the access arrangement relates and to make reference to a website where a description of the pipeline can be inspected.

DBP's Proposed Revisions

26. Clause 2 of the proposed revised access arrangement identifies the DBNGP as the pipeline to which the access arrangement relates. The DBNGP is indicated to comprise of assets that are described in the following pipeline licences (**PL**) issued under the *Petroleum Pipelines Act 1969 (WA)*:

- PL 40 (as amended or varied before the date the revisions to the access arrangement have effect under clause 14.1 of the access arrangement);
- PL 41 (as amended or varied before the date the revisions to the access arrangement have effect under clause 14.1 of the access arrangement);
- PL 47 (as amended or varied before the date the revisions to the access arrangement have effect under clause 14.1 of the access arrangement);
- PL 69 (as amended or varied before the date the revisions to the access arrangement have effect under clause 14.1 of the access arrangement); and
- an amount of capacity of the Burrup Extension Pipeline (**BEP**),[6] if at the commencement of the revised access arrangement an agreement between DBP and the owners of the BEP (**BEP Agreement**) has commenced.

27. A description of the DBNGP is provided on DBP's website at http://www.dbp.net.au.

28. DBP's proposed revised access arrangement includes a change in the description of the pipeline: (i) the addition of assets described in PL 69; and (ii) leased capacity of the BEP. PL 69 relates to a lateral pipeline from the DBNGP to the Kemerton Industrial Area (hereafter referred to as the Kemerton Lateral). The BEP is a 24 km length of pipeline commissioned in 1996 and owned by Epic Energy. The pipeline commences at the North West Shelf Domgas Plant and runs close and parallel to the DBNGP to connect to the Pilbara Energy Pipeline. The BEP Agreement provides for DBP to lease part of the capacity of the BEP and operate the BEP as the first loop of the DBNGP. DBP proposes that an amount of leased capacity of the BEP be included under the access arrangement, rather than the physical pipeline asset.

29. If these pipeline assets are included under the access arrangement, it will follow that the assets form part of the covered pipeline of the DBNGP. DBP proposes to include an amount of value attributable to these assets to the capital base of the DBNGP (as addressed elsewhere in this draft decision).

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6 The BEP is described in PL 38 issued under the *Petroleum Pipelines Act 1969 (WA)*.

Submissions

30. No submissions made to the Authority address the description of the pipeline.

Considerations of the Authority

31. DBP's proposed revised access arrangement identifies the DBNGP as the pipeline to which the access arrangement relates. A description of the DBNGP is contained in a document that is available for inspection on DBP's website. DBP has advised that the document is titled "Dampier to Bunbury Natural Gas Pipeline System: Description of the Gas Transmission System as at 22 September 2009".[7]

32. The proposed revised access arrangement and DBP's website provides separate information on the description of the pipeline system. As such, interested parties have to cross check the pipeline assets in the pipeline description document on DBP's website with the covered pipeline assets listed in the access arrangement to fully understand the nature of the covered pipeline asset(s). The existing access arrangement information document includes the full pipeline description as an attachment.[8]

33. The pipeline description document on DBP's website does not appear to be kept up to date. At the date of the draft decision, this pipeline description does not include the leased capacity in the BEP despite the BEP lease having come into effect.

34. The Authority considers that compliance with rule 48(1)(a) of the NGR requires that the access arrangement include a comprehensive description of the pipeline. The Authority considers that a simple listing of pipeline licences for parts of the DBNGP does not satisfy this requirement. The Authority further considers that the level of detail required to comply with the NGR should be to the same level of detail as the description provided in the access arrangement information for the current access arrangement.

Required Amendment 1

The proposed revised access arrangement should be amended to include a full description of the DBNGP to the same level of detail as set out in the access arrangement information.

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7 Email correspondence from DBP to ERA, 21 June 2010, *Dampier to Bunbury Natural Gas Pipeline System: Description of the Gas Transmission System as at 22 September 2009*, viewed 14 July 2010, <http://www.dbp.net.au/files/DBNGP_Pipeline_Description_22_Sept_2009_Rev6.pdf>.

8 Approved Revised Access Arrangement Information, Annexure 1: <http://www.erawa.com.au/3/365/48/dampier_to_bunbury_natural_gas_pipeline__revised_a.pm>

Pipeline Services

Regulatory Requirements

35. A 'pipeline service' is defined under section 2 of the NGL(WA).

Pipeline service means—

(a) a service provided by means of a pipeline, including—

(i) a haulage service (such as firm haulage, interruptible haulage, spot haulage and backhaul); and

(ii) a service providing for, or facilitating, the interconnection of pipelines; and

(b) a service ancillary to the provision of a service referred to in paragraph (a),

but does not include the production, sale or purchase of natural gas or processable gas.

36. Under rule 48(1) of the NGR, a full access arrangement proposal must:

- identify the pipeline to which the access arrangement relates (rule 48(1)(a));
- describe the pipeline services the service provider proposes to offer to provide by means of the pipeline (rule 48(1)(b)); and
- specify the reference services (rule 48(1)(c)).

37. Rule 101 of the NGR requires a full access arrangement to specify all reference services.

101 Full access arrangement to contain statement of reference services

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

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

DBP's Proposed Revisions

38. Clause 3 of the proposed revised access arrangement includes a description of the pipeline services to be offered by means of the DBNGP. These services comprise one reference service, the full haul R1 service (the "**R1 Service**"), and several non-reference services.

39. DBP's proposal differs from the current 2005 to 2010 access arrangement in that:

- the proposed R1 Service has different characteristics than the full haul reference service offered under the current access arrangement (that is, the T1 Service); and
- the three existing reference services under the current access arrangement – the T1 Service, P1 Service (a part haul service) and B1 Service (a back haul service) – are proposed to be non-reference services.

40. The proposed non-reference services offered subject to availability of capacity or operational ability.

- Non-reference services subject to the availability of capacity are:
  - firm full haul T1 service ("T1 Service");
  - part haul T1 service ("P1 Service");
  - back haul T1 service ("B1 Service");
  - spot capacity service;
  - park and loan service; and
  - seasonal service.
- Non-reference services subject to operational availability are:
  - peaking service;
  - metering information service;
  - pressure and temperature control service;
  - odorisation service;
  - co-mingling service;
  - pipeline impact agreement service; and
  - interconnection service.

41. Descriptions of the R1 Service and of non-reference services are provided in clauses 3.2 to 3.6 of the proposed revised access arrangement. DBP has included proposed terms and conditions for the proposed R1 Service ("R1 Terms and Conditions") at Appendix 1 of the proposed revised access arrangement.

42. DBP has provided the Authority with further information in a confidential supporting submission to justify the inclusion of the R1 Service as the only reference service to be offered under the proposed revised access arrangement.[9]

The market for pipeline services

43. DBP submits that in considering the relevant market for pipeline services the Authority:

- must not have regard to access contracts that have already been entered and the services to be provided under those contracts (**pre-existing contracts**) and any incremental demand that arises from exercising capacity expansion rights under these contracts;
- should only have regard to prospective users for each pipeline service, not for the market of prospective shippers for all pipeline services on the pipeline aggregated together, or the market of existing shippers under pre-existing contracts;
- should have evidence of contracts for such services being entered into; and

9 DBP, 14 April 2010, confidential supporting submission 3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au.

- must have regard to whether there is spare, uncontracted capacity and, if this is not relevant, the likelihood of any future expansions.[10]

Submissions

44. Submissions to the Authority have addressed DBP's proposal to revise the pipeline services to be offered as reference services. The matters raised in submissions are summarised below.

45. Several users of the DBNGP submit that the existing T1, P1 and B1 reference services are pipeline services that are currently sought by a significant part of the market and should be offered as reference services under the proposed revised access arrangement.[11]

46. The majority of submissions claim that there is no evidence that the proposed R1 reference service is a service that would be sought by a significant part of the market because the proposed R1 Service is of a subordinate quality to the existing T1 Service.[12] Reasons for establishing that the proposed R1 service is of a subordinate quality to the existing T1 Service include:

    - the R1 Service has lower reliability;[13]
    - the R1 Service is of higher cost;[14]
    - the R1 Service does not have terms for an outer imbalance band and outer hourly peaking band;[15]
    - the R1 Service has significant increases in penalties for overrun, imbalance and hourly peaking excursions;[16]
    - the R1 Service includes a requirement that shippers agree to an inlet sales agreement to nominate on behalf of another shipper;[17]
    - the R1 Service requires the cashing out of imbalances at the end of the month, rather than at the end of each contract;[18]

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10 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4). A public version of this submission is available at www.erawa.com.au.

11 The T1 Service is supported by Alinta, BHP Billiton, BP, Synergy, and Verve Energy. The P1 Service is supported by Alinta, BHP Billiton, Verve Energy, APA, Chevron, ERM, NewGen, and Synergy. The B1 Service is supported by Alinta, BHP Billiton, Verve Energy, APA, Chevron, ERM, NewGen, and Synergy.

12 Alinta Pty Ltd, submission of 9 July 2010; BP Australia Pty Ltd, submission of 6 July 2010; BHP Billiton, submission of 9 July 2010; Rio Tinto, submission of 20 July 2010; Synergy, submission of 9 July 2010; Verve Energy, submission of 9 July 2010, ERM Power Pty Ltd, submission of 7 July 2010; and NewGen Power Kwinana Pty Ltd, submission of 9 July 2010.

13 Alinta Pty Ltd, submission of 9 July 2010; and BHP Billiton, submission of 9 July 2010.

14 Alinta Pty Ltd, submission of 9 July 2010; BHP Billiton, submission of 9 July 2010; BP Australia Pty Ltd, submission of 6 July 2010; ERM Power Pty Ltd, submission of 7 July 2010; and NewGen Power Kwinana Pty Ltd, submission of 9 July 2010.

15 Alinta Pty Ltd, submission of 9 July 2010.

16 Alinta Pty Ltd, submission of 9 July 2010.

17 Alinta Pty Ltd, submission of 9 July 2010.

18 Alinta Pty Ltd, submission of 9 July 2010.

- the R1 Service includes a significant expansion of the circumstances in which DBP can refuse to accept or deliver gas, or to curtail, without liability;[19]
- the R1 Service entails a different method for determining capacity quantities;[20] and
- the R1 Service does not include a concept equivalent to the "aggregated T1 Service".[21]

47. Several parties that made submissions to the Authority disagree with DBP's assertion that the "relevant market" assessment under rule 101 of the NGR should be limited to prospective shippers.[22] In addition, Alinta argues that DBP's interpretation is contrary to the national gas objective which refers to long term benefit for consumers of gas. Alinta also argues that DBP's interpretation of the relevant market is contrary to rule 42(1) of the NGR, requiring access arrangement information to enable "users and prospective users" to understand the basis and derivation of the various elements of the access arrangement or the access arrangement proposal.[23] That is, the law and the access arrangement are intended to encompass all users whether current or prospective.

48. Contrary to DBP's proposal, several parties submit that existing demand for existing reference services (that is, the T1, P1 and B1 Services) should be taken into account when determining reference services in accordance with rule 101(2).[24]

49. An associated issue raised by several submissions[25] is the flow on impact of the proposed R1 reference service (and associated terms and conditions), including on the secondary gas market, although many of these submissions explain how the proposed revised access arrangement adversely affects this market.

50. Several parties submit that the "special circumstances" associated with the 2004 re-commercialisation of the DBNGP limits the attractiveness of the proposed R1 Service to existing and prospective shippers that have access to the T1 Service on more attractive terms and conditions at the same price.[26]

51. Several parties submit that additional reference services are necessary to accommodate gas storage facilities.[27] In particular, the APA Group submits that a range of additional reference services should be included to support development and use of the Mondarra Gas Storage Facility (**MGSF**), including:

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19 Alinta Pty Ltd, submission of 9 July 2010.

20 Alinta Pty Ltd, submission of 9 July 2010.

21 Alinta Pty Ltd, submission of 9 July 2010.

22 For example, Alinta, BHP Billiton, Synergy, and Verve Energy public submissions.

23 Alinta Pty Ltd, submission of 9 July 2010.

24 For example, Synergy and Verve Energy public submissions.

25 APA Group, submission of 9 July 2010; BP Australia Pty Ltd, submission of 6 July 2010; BHP Billiton, submission of 9 July 2010; and Wesfarmers Chemicals, Energy and Fertilisers, submission of 9 July 2010.

26 Alinta, BHP Billiton, Rio Tinto, and Verve Energy.

27 Alinta Pty Ltd, submission of 9 July 2010; Verve Energy, submission of 9 July 2010; and APA Group, submission of 8 July 2010.

- a "contract" and "spot" firm forward haul service from the Carnarvon Basin (i.e. Pilbara region) to Mondarra under a (cost reflective) distance based tariff;
- a "contract" and "spot" firm forward haul service from Mondarra south to the South West region under a (cost reflective) distance based tariff;
- a "contract" and "spot" back haul service from the South West to any point north;
- individual maximum daily quantities (**MDQs**) for each service identified above, in order to accommodate load factor management for transport services physically upstream of the MGSF;
- bi-directional (i.e. inlet and outlet) connection to the DBNGP at Mondarra with reasonable inlet and outlet conditions (e.g. pressure and temperature);
- nominations and allocation procedures to accommodate bi-directional inlet and outlet connections to the DBNGP, including accommodation of time required to perform flow reversals; and
- discretionary linking, but not compulsory bundling, of "contract" forward haul and back haul services associated with use of the MGSF to promote flexibility of storage and pipeline utilisation.

52. The APA Group has identified a demand for storage services from the MGSF in excess of 100 TJ/d, which it views as a significant part of the Western Australian gas market. Part haul and back haul services on the DBNGP will support bi-directional transport of gas from the DBNGP into and out of the MGSF.

53. Some parties also submit that a range of additional reference services are likely to be demanded by a significant part of the market, including a “spot capacity service” and “inlet sales service”.[28]

Considerations of the Authority

54. In assessing DBP’s proposal to include the proposed R1 Service as the only reference service the Authority has considered the following matters:

    - the market for pipeline services that are offered by means of the DBNGP;
    - whether the proposed R1 Service is a service likely to be sought by a significant part of that market; and
    - whether there are other pipeline services that should be included as reference services.

55. Rule 48(1)(b) requires that the access arrangement include a description of the pipeline services that the service provider proposes to offer using the pipeline. Therefore, the Authority has also given consideration to whether the access arrangement should include a description of any services that should be included under the access arrangement in addition to the non-reference services described under the proposed revised access arrangement.

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[28] APA Group, submission of 8 July 2010; BHP Billiton, submission of 9 July 2010; and BP Australia Pty Ltd, submission of 6 July 2010.

The market for pipeline services

56. Having regard to the matters raised in submissions, the Authority is of the view that pre-existing contracts between DBP and users are an important indicator of the relevant market for pipeline services. Existing contracts and the services procured under these contracts, whether reference services or other pipeline services, including those contracted for under a contract outside of the regulatory regime, are indicative of the demand for services.

57. More particularly, the Authority is of the view that rule 101 is concerned with the pipeline services that are *likely* to be sought by users of the pipeline, rather than what pipeline services the service provider proposes to offer via the pipeline.

58. The Authority notes that the broad requirement of the national gas objective is served through the provision of services that are likely to be sought by a significant part of the market.

59. In addition to the existing demand for pipeline services, the Authority is of the view that new services may be sought by a significant part of the market. This would be due to either new users or existing users seeking pipeline services with different characteristics, or as a result of changes in patterns of energy use and management of an energy supply chain**.**

60. As such, the Authority considers that rule 101(2) requires consideration of the nature of services demanded by users and prospective users, unconstrained by the availability of pipeline capacity to expand the provision of services during the course of the relevant access arrangement period. This is consistent with the approach adopted by the Authority in its determination for the approval of the current 2005 to 2010 access arrangement under the Gas Code.[29]

61. Reference services offered under the current 2005 to 2010 access arrangement period were determined by having regard to the nature of services obtained by users under contracts entered into just prior to the Authority's consideration of the proposed revisions to the access arrangement. In particular, the Authority had regard to the nature of the services obtained by the majority of users under the standard shipper contract.[30] The Authority considers that the standard shipper contract remains a relevant consideration in determining the nature of services that are likely to be sought by a significant part of the market over the course of the 2011 to 2015 access arrangement period.

[29] Economic Regulation Authority, 2005, Final Decision on the Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (reprinted 11 November 2005), paragraph 51.

[30] Economic Regulation Authority, 2005, Final Decision on the Proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (reprinted 11 November 2005), paragraph 56.

Should the proposed R1 Service be included in the access arrangement as a reference service?

62. DBP submits that the proposed R1 Service will be more attractive to shippers and encourage shippers to access capacity on the DBNGP as a result of the changes that have been made to the existing T1 Service.[31] The proposed R1 Service is different to the T1 Service in that:

- it does not include additional behavioural features, such as extended peaking and imbalance rights;
- the method for defining the availability of the service is different; and
- the R1 Service will be curtailed as if it were a firm service (for the purposes of applying the curtailment plan in the SSC for the T1 Service).

63. DBP states that the terms and conditions for the R1 Service, while based on the terms and conditions of the T1 Service, have been modified to deal with such things as:

- the reduction in behavioural limits that will enable more capacity to be made available to the R1 Service than the T1 Service; and
- the practical experience of operating under the T1 Service terms and conditions.

64. As indicated previously, a number of users of the DBNGP have addressed the proposed R1 Service in submissions to the Authority. These users consistently submit that the proposed R1 service is of an inferior quality to the existing T1 Service and that they would not be seeking to use the R1 Service. Taking into account these submissions, and the absence of any submissions that indicate demand for the proposed R1 Service, the Authority is of the view that a service in the nature of the R1 Service is unlikely to be sought by a significant part of the market. Accordingly, the proposed R1 Service does not meet the requirements for a reference service under rule 101 of the NGR.

Required Amendment 2

The proposed revised access arrangement should be amended to remove the proposed R1 Service as a reference service.

Should other pipeline services be included in the access arrangement as reference services?

Existing reference services

65. The current access arrangement provides for the following reference services:

- a full haul T1 service (**T1 Service**);
- a part haul T1 service (**P1 Service**); and

[31] DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4.8). A public version of this submission is available at www.erawa.com.au.

- a back haul T1 service (**B1 Service**);

66. DBP submits that these pipeline services do not meet the requirements to be reference services in that each service:
    - is not likely to be sought during the access arrangement period; or
    - is not likely to be sought by a significant part of the market, to the extent that there is likelihood for the pipeline service not to be sought during the access arrangement period.[32]

67. Specifically, DBP submits that it does not expect any additional amount of the T1 Service to be sought by users during the 2011 to 2015 access arrangement period over and above the amount of the T1 Service obtained under current contracts. DBP similarly submits that the P1 Service and B1 Service are not likely to be sought by users during the 2011 to 2015 access arrangement period over and above the amount of the P1 and B1 Services obtained under current contracts.

68. For reasons already set out in this draft decision (paragraphs 56 to 59, above), the Authority is of the view that the question, under rule 101(2) of the NGR, of whether a pipeline service is likely to be sought by a significant part of the market requires consideration of the nature of services sought by users and prospective users, unconstrained by the availability of pipeline capacity to expand the provision of services during the course of the relevant access arrangement period. That is, the Authority is of the view that the question of whether a pipeline service is likely to be sought by a significant part of the market requires consideration of the totality of demand for services and should not be limited to consideration of only incremental demand over and above the quantum of services already contracted for under existing contracts.

69. On this basis, the Authority rejects DBP's submission that the T1, P1 and B1 Services will not be sought during the 2011 to 2015 access arrangement period. The Authority has instead considered whether the existing demand for the T1, P1 and B1 Services is likely to be maintained during the 2011 to 2015 access arrangement period.

70. The Authority considers that there is evidence that demand for the T1 Service, P1 Service and B1 Service will be maintained during the 2011 to 2015 access arrangement period. In particular:
    - historic and forecast volume data for each of the reference services submitted by DBP indicate that existing reference services are likely to continue to be sought by a significant part of the market;[33] and
    - submissions from interested parties indicate that they will continue to seek the existing reference services.[34]

71. The Authority is therefore of the view that the existing reference services, the T1, P1 and B1 Services are likely to be sought by a significant part of the market.

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[32] DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 5). A public version of this submission is available at www.erawa.com.au.

[33] DBP, 1 April 2010, Confidential supporting submission 7: Capacity and throughput forecast 2010-2015 (paragraph 4.4). A public version of this submission is available at www.erawa.com.au.

[34] Refer to footnote 11.

72. DBP submits that inclusion of the T1 Service as a reference service under the access arrangement will create difficulties for DBP under the terms of the SSC that DBP holds with existing users of the DBNGP. DBP provides reasoning for this in its confidential supporting submission 3 and an excerpt of this is contained in a confidential annexure to this decision.[35]

> Firstly, clause 20.5 of the terms and conditions for the T1 Service [under the Standard Shipper Contract] requires the Operator, once it considers the action to be appropriate, to file an access arrangement with an Equivalent T1 Reference Service. However, if it is filed before 2016, the Reference Tariff must be the negotiated tariff. However, prior to 2016, the negotiated tariff could be higher than the reference tariff the ERA may set for this T1 Service. That is, the Regulator could be likely to approve a reference tariff which is significantly lower than the negotiated tariff. Were this to be the case, this could trigger "most favoured nations" clauses in at least two contracts which in turn would enable the shippers to pay the reference tariff instead of the negotiated tariff for T1 Service. As a result, the economics of pipeline acquisition by the current owners would be undermined.
>
> Secondly, the Operator would be in breach of clause 20.5 of the Standard Shipper Contract if the Operator were to submit proposed revisions to the access arrangement, which, if adopted, would have the outcome of including the T1 Service as a reference service but with something other than the negotiated tariff as the reference tariff for the T1 Service. This could then entitle a shipper to terminate its access contract for the T1 Service. This would be unacceptable to the current owners of the DBNGP and could lead to significant uncertainty for future investment.

73. The Authority does not accept that any contractual difficulty that may be experienced by DBP constitutes a basis for not including the T1 Service as a reference service in the access arrangement. The contractual difficulties that DBP may encounter do not constitute a deprivation of a contractual right for which DBP may receive protection under section 321 of the NGL. Rather, the contracting difficulties referred to by DBP represent an outworking of contractual terms that contemplate the potential consequences and allocation of risk in the event of the T1 Service is included in the access arrangement as a reference service.

74. In addition, in relation to P1 and B1 Services, the Authority considers that resource projects north of, or off, the Goldfields Gas Pipeline as well as the MGSF increases the likelihood of demand for these services.

75. Taking into account the above matters, the Authority considers that the T1, P1 and B1 Services are likely to be sought be a significant part of the market and should be maintained in the access arrangement as reference services.

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[35] DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (sections 5.10 and 5.11). A public version of this submission is available at www.erawa.com.au.

Required Amendment 3

The proposed revised access arrangement should be amended to include, as reference services, the T1 Service, P1 Service and B1 Service as described in the current access arrangement.

Existing non-reference pipeline services

76. The Authority has considered whether the access arrangement should include, as reference services, any services other than the T1, P1 and B1 Services.

77. The DBNGP is used to provide a range of pipeline services in addition to the T1, P1 or B1 Services, or of the nature of these services. This includes a range of non-reference services described in the current 2005 to 2010 access arrangement as well as some other services that have been contracted with users under the SSC.

78. The current access arrangement provides the following non-reference services:

- spot capacity service;
- park and loan service;
- seasonal service;
- peaking service;
- metering information service;
- pressure and temperature control service;
- odorisation service; and
- comingling service.

79. The SSC includes an "other reserved service", defined as:

> [A] Capacity Service offered under a contract which, in the Operator's opinion acting reasonably, has a capacity reservation charge or an allocation reservation deposit or any material equivalent to such charge or deposit which is payable up front or from time to time in respect to the reservation of capacity under that contract for at least a reasonable time into the future (but at all times excluding a T1 Service, a Firm Service and Capacity under a Spot Transaction).

80. The other reserved services include services designated as the:

- "Tk Service", being a peaking service specific to Verve Energy;[36]
- "Tp Service", being a service that offers shippers who have contracted additional capacity as part of the Stage 5A Expansion project under the SSC access to interruptible capacity at times when the actual heating value of gas distribution in the pipeline is higher than the minimum specification, giving rise to additional pipeline capacity for the provision of services;[37]

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36 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 6). A public version of this submission is available at www.erawa.com.au.

37 DUET (p. 50) http://www.duet.net.au/web/au/duet/investor-centre/investor-guides.

- "Tx Service", being an interruptible service specific to Western Power;[38]
- "Ty Service", being a firm service specific to Western Power;[39] and
- "Tw Service", being an interruptible service specific to Alinta Sales.[40]

81. The level of use of these services during the current access arrangement period is indicated in Table 1 below.

Table 1 Average contracted capacity and throughput over the 2006 to 2010 access arrangement period[41]

Pipeline Service	Average contracted (TJ/d)	Average throughput (TJ/d)
Tk, Tp, Tw, Tx, Ty Services	43.747	20.313
Spot, Spot take or pay	0.210	1.655
Park and Loan and Storage and Delivery	-	0.340
Interruptible, Interruptible Reservation	5.768	-
Commingling, Commingling Reservation	0.167	-
Other, Other Reservation (Inlet Sales fees, out of spec, comp fuel, commissioning)	1.969	13.115
Other (seasonal service, peaking service, metering service, pressure and temperature control service, odorisation service)	np	np

Note: np – not provided

82. DBP submits that the non-reference services specified under the current access arrangement are not sought by a significant part of the market due to low throughput, few shippers and short contract periods.[42]

83. Furthermore, DBP submits that:

- the Tx Service is a service that is no longer available to shippers as there is no capacity left on the DBNGP to provide such a service and it is also not a service requested by any shipper or prospective shipper; and
- the Tp Service is, in fact, not generally available to shippers and was only extended to shippers participating in the Stage 5A project.[43]

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38 DBNGP Standard Shipper Contract, clause 1. "Tx Service" has the meaning given in the Diversified Utility and Energy Trust (DUET) Product Disclosure Statement for the issue of 164.6 million New Stapled Units dated November 2004. The DUET Product Disclosure Statement (19 November 2004, p. 154) indicates that "Tx Service" is a capacity service in the Western Power Standard Shipper Contract.

39 DUET Product Disclosure Statement, 19 November 2004, p. 156. "Ty Service" is a capacity service in the Western Power Standard Shipper Contract.

40 DUET Product Disclosure Statement, 19 November 2004, p. 156. "Tw Service" is a capacity service in the Alinta Sales Standard Shipper Contract.

41 Aggregated information from DBP Submission 35.

42 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 6). A public version of this submission is available at www.erawa.com.au.

43 DBP, 26 May 2010, Submission 13: Response to ERA Issues Paper.

84. In terms of existing pipeline services, the Authority is of the view that the volumes of the services (referred to in paragraphs 79 to 81) sought during the current (2005 to 2010) access arrangement period, and likely to be sought during the next (2011 to 2015) access arrangement period, do not constitute a significant part of the market.

85. The Authority also observes that submissions by interested parties do not address the matter of whether any of these services should be reference services, and the Authority is not aware of quantitative information on the use of any of these services that contradicts DBP's submission.

86. Taking these matters into account, the Authority is of the view that there is no basis for any of the existing non-reference services provided by means of the DBNGP to be included in the access arrangement as reference services.

New pipeline services likely to be sought by a significant part of the market

87. The Authority has given consideration to whether any additional services not previously offered as reference services or non-reference services should be included in the access arrangement as reference services. In doing so, the Authority has had regard to submissions from interested parties.

88. The APA Group submits that a range of additional reference services should be included to support development and use of the MGSF, as indicated at paragraph 51. [44]

89. DBP submits that the gas production opportunities that might exist south of Mondarra are not likely to materialise in the next five years. DBP also submits that:

- it is not in receipt of any request for access to capacity at the Mondarra outlet point or any other outlet point for delivery in the MGSF;
- the DBNGP does not directly connect to the MGSF and there is a need for shippers to access some of APA's facilities to access the MGSF; and
- while DBP is eager to support the growth of additional gas fields to create competition in the upstream market, there is no evidence to justify that these new fields will be able to be commercialised. [45]

90. The Authority has considered submissions from interested parties and DBP and accepts that there is a reasonable prospect of increased use of the MGSF during the course of the 2011 to 2015 access arrangement period, and of this facility being used by a significant part of the market. In particular, the Authority observes that the Western Australian Government is contemplating greater use of gas storage as a means of achieving greater security of gas supplies.[46]

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44 APA Group, submission of 9 July 2010.

45 DBP, 6 August 2010, Confidential submission 26: Response to 3rd Party Submissions. (Section 8.12 – 8.16) A public version of this submissions is available at: www.erawa.com.au

46 Government of Western Australia Office of Energy, September 2009, Gas Supply and Emergency Management Committee Report to Government. A recommendation of this report is that the Government "require gas retailers to have adequate back-up supply arrangements to ensure continuity of supply for small use customers on standard contracts, with standard tariffs, (such as residential and small business customers) and offer such back-up supply arrangements as an opt-in service for other gas distribution system customers". The report explicitly recognises the potential to use the Mondarra gas storage facility as a means of meeting a storage requirement.

91. Having regard to the prospect of increased use of the MGSF, the Authority considers that reference services under the access arrangement should support use of the facility. The Authority is of the view that the P1 Service and the B1 Service under the current (2005 to 2010) access arrangement and required by the Authority to be included in the access arrangement for the 2011 to 2015 access arrangement period, support the use of the MGSF. The P1 Service accommodates part haul transport of gas at a per km tariff rate from the Carnarvon Basin to an outlet point at Mondarra, and from an inlet point at Mondarra to an outlet point south of Mondarra. The B1 Service accommodates the back haul "transport" of gas at a per km tariff rate from an inlet point at Mondarra to an outlet point north of Mondarra. There does not appear to be anything in the existing terms and conditions for P1 and B1 Services that prevents a single point of connection with the DBNGP (to take gas to or from the MGSF) being both an inlet and outlet point.

92. Taking these matters into consideration, the Authority is of the view that the reference services under the current access arrangement, and required by the Authority for the proposed revised access arrangement, support use of the MGSF. However, while there may be particular requirements in services for transport of gas to, or from, the MGSF, such as matters of gas pressure and temperature, the Authority considers that these would be idiosyncratic to the use of the MGSF and would be unlikely to be sought by a significant part of the market. Accordingly, the Authority is of the view that no additional pipeline services should be included in the access arrangement as reference services.

Pipeline services other than reference services to be included in the access arrangement

93. Under the NGR, an access arrangement is required to include a description of pipeline services (rule 48(1)(b)). This includes non-reference services, which are broader than the pipeline services that are likely to be sought by a significant part of the market and are therefore required as "reference services" under the access arrangement.

94. DBP has included in the proposed revised access arrangement a range of non-reference (pipeline) services, which are of the same nature as pipeline services included historically (refer to paragraph 78 of this draft decision). Interested parties have made no specific submissions on these services.

95. In relation to DBP's proposed non-reference services, the same pipeline services are included in the approved access arrangement and the Authority has no submissions or evidence before it, at this time, to suggest that the relevant market conditions have changed since its 2005 final decision or that its conclusion as set out in the previous 2005 final decision was unsound. However, the Authority observes that a range of pipeline services appear to be offered by means of the DBNGP that are not described in the proposed revised access arrangement. The services that the Authority is aware of are the "Tx Service", "Ty Service", and "Tp Service".

96. As previously indicated, in relation to these services, DBP has advised that:

- the Tx Service is a service that is no longer available to shippers as there is no capacity left on the DBNGP to provide such a service and it is also not a service requested by any shipper or prospective shipper; and
- the Tp Service is not generally available to shippers and was only extended to shippers participating in the Stage 5A project.[47]

97. The Authority is of the view that whether or not there is additional capacity available for a particular pipeline service is not a relevant consideration under rule 48(1)(b). Rather, the relevant issue is whether or not the service provider proposes to offer to provide the pipeline service.

98. The Authority understands that the Tp, Tx and Ty Services continue to be provided under long term contracts and continue to be offered or made available to users by DBP. For instance, the Tp Service is explicitly available to T1 shippers under the T1 shipper contract. As such, the Authority is of the view that DBP is likely to continue to offer these services to parties that have such contracts and, hence, these services should be described in the access arrangement in accordance with rule 48(1)(b).

Required Amendment 4

The proposed revised access arrangement should be amended to include descriptions of the Tp, Tx and Ty Services and any other pipeline services that DBP is making available or will offer during the relevant access arrangement period.

Total Revenue

Regulatory Requirements

99. Rule 76 of the NGR provides that total revenue is to be determined for each regulatory year of the access arrangement period using a building block approach in which the building blocks are:

- a return on the projected capital base for the year; and
- depreciation on the projected capital base for the year; and
- if applicable – the estimated cost of corporate income tax for the year; and
- increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency; and
- a forecast of operating expenditure for the year.

100. The parameters relevant to the building blocks that make up total revenue (capital expenditure, depreciation, rate of return and operating expenditure) are addressed in the following sections of this draft decision.

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47 DBP, 26 May 2010, Submission 13: Response to ERA Issues Paper.

Basis for Financial Information

Regulatory Requirements

101. Rule 73 of the NGR contains specific requirements for the provision by the service provider of financial information.

> 73 Basis on which financial information is to be provided.
>
> (1) Financial information must be provided on:
>
> (a) a nominal basis; or
>
> (b) a real basis; or
>
> (c) some other recognised basis for dealing with the effects of inflation.
>
> (2) The basis on which financial information is provided must be stated in the access arrangement information.
>
> (3) All financial information must be provided, and all calculations made, consistently on the same basis.

DBP's Proposed Revisions

102. Section 2 of the revised access arrangement information sets out the basis on which financial information is provided.

- Financial information is provided in real terms with all values expressed in dollar values of December 2009.
- Real values of financial information have been calculated by applying escalation factors derived from December quarter values of the Consumer Price Index (All Groups, Perth).
- Financial data is provided on a calendar year basis.

Submissions

103. None of the submissions received by the Authority addressed the basis on which DBP has presented financial information.

Considerations of the Authority

104. The Authority is satisfied that provision of financial information expressed in real values is consistent with the requirements of Rule 73.

105. However, the Authority is not satisfied that DBP has adopted a consistent treatment of inflation in its financial calculations. The use of escalation factors based on a measure of inflation for Perth (the all-groups Perth CPI) is inconsistent with the rate of return applied in the calculation of Total Revenue. The rate of return is estimated using a forecast of inflation for the Australian economy, consistent with an implicit assumption made in determination of the rate of return of the DBNGP that the DBNGP is being financed by Australian investors.

106. In this draft decision, the Authority has undertaken calculations of total revenue in real terms with real values of financial information calculated by applying escalation factors derived from December quarter values of the Consumer Price Index (All Groups, Eight Capital Cities). The Authority has also undertaken financial calculations using values of financial information expressed in dollar values of 31 December 2010. For consistency with these calculations, all financial values presented in this draft decision are expressed in dollar values of 31 December 2010, unless otherwise indicated.

Capital Base

Regulatory Requirements

Opening Capital Base

107. Rule 77(2) of the NGR establishes the approach to determine the opening capital base for an access arrangement period that follows immediately on the conclusion of a preceding access arrangement period.

108. Under Rule 77(2), the opening capital base for the later access arrangement period is to be:

(a) the opening capital base as at the commencement of the earlier access arrangement period (adjusted for any differences between estimated and actual capital expenditure);

plus:

(b) conforming capital expenditure made, or to be made, during the earlier access arrangement period;

plus:

(c) any amounts to be added to the capital base under rule 82 [capital contributions by users], rule 84 [speculative capital expenditure account] or rule 86 [re-use of redundant assets];

less:

(d) depreciation over the earlier access arrangement period (to be calculated in accordance with any relevant provisions of the access arrangement governing the calculation of depreciation for the purpose of establishing the opening capital base); and

(e) redundant assets identified during the course of the earlier access arrangement period; and

(f) the value of pipeline assets disposed of during the earlier access arrangement period.

Projected Capital Base

109. Rule 78 of the NGR establishes the approach to determine the projected capital base for an access arrangement period.

110. Under rule 78, the projected capital base for a particular period is:

(a) the opening capital base;

plus:

(b) forecast conforming capital expenditure for the period;

less:

(c) forecast depreciation for the period; and

(d) the forecast value of pipeline assets to be disposed of in the course of the period.

Conforming Capital Expenditure

111. Conforming capital expenditure is capital expenditure that conforms with criteria under rule 79 of the NGR:

(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:

(a) the capital expenditure must be 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 of providing services;

(b) the capital expenditure must be justifiable having regard to one of the following grounds stated in rule 79(2).

(2) Capital expenditure is justifiable if:

(a) the overall economic value of the expenditure is positive; or

(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or

(c) the capital expenditure is necessary:

(i) to maintain and improve the safety of services; or

(ii) to maintain the integrity of services; or

(iii) to comply with a regulatory obligation or requirement; or

(iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or

(d) the capital expenditure is an aggregate amount divisible into 2 parts, one referable to incremental services and the other referable to a purpose referred to in paragraph (c), and the former is justifiable under paragraph (b) and the latter under paragraph (c).

(3) In deciding whether the overall economic value of capital expenditure is positive, consideration is to be given only to economic value directly accruing to the service provider, gas producers, users and end users.

(4) In determining the present value of expected incremental revenue:

(a) a tariff will be assumed for incremental services based on (or extrapolated from) prevailing reference tariffs or an estimate of the reference tariffs that would have been set for comparable services if those services had been reference services;

(b) incremental revenue will be taken to be the gross revenue to be derived from the incremental services less incremental operating expenditure for the incremental services; and

(c) a discount rate is to be used equal to the rate of return implicit in the reference tariff.

(5) If capital expenditure made during an access arrangement period conforms, in part, with the criteria laid down in this rule, the capital expenditure is, to that extent, to be regarded as conforming capital expenditure.

(6) The [Authority's] discretion under this rule is limited.

112. Rule 79 is supplemented by clause 7(2) of Schedule 1 to the NGR:

7 Additional criteria related to capital expenditure for WA transmission pipelines

…

(2) In making a relevant decision under rule 79(3) on whether the overall economic value of capital expenditure is positive, the [Authority] must consider not only the economic value directly accruing to the service provider, gas producers, users and end users (as required by rule 79(3)) but also material economic value that is likely to accrue directly to electricity market participants and end users of electricity from additional gas fired generation capacity.

113. Rule 71 of the NGR is relevant to the Authority's consideration of actual and forecast capital expenditure against the requirements of rule 79. It states that:

71 Assessment of compliance

(1) In determining whether capital or operating expenditure is efficient and complies with other criteria prescribed by these rules, the [Economic Regulation Authority] may, without embarking on a detailed investigation, infer compliance from the operation of an incentive mechanism or on any other basis the [Authority] considers appropriate.

(2) The [Authority] must, however, consider and give appropriate weight to, submissions and comments received when the question whether a relevant access arrangement proposal should be approved is submitted for public consultation.

Capital Redundancy

114. Rule 77(2) of the NGR provides that the opening capital base for an access arrangement period may exclude redundant assets identified during the course of the earlier access arrangement period. This is subject to the access arrangement including a mechanism under rule 85 to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base.

115. Rule 85(1) of the NGR provides that a full access arrangement may include a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services are removed from the capital base. Rule 85(2) of the NGR provides that a reduction of the capital base in accordance with such a mechanism may only take effect from the commencement of the first access arrangement period to follow the inclusion of the mechanism in the access arrangement, or the commencement of a later access arrangement period.

116. Rule 85(4) of the NGR provides that before requiring or approving a capital redundancy mechanism, the Authority must take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users.

Capital Contributions

117. Rule 82 of the NGR deals with the addition to the capital base of capital expenditure in respect of which a user has paid a capital contribution to the service provider. Rule 82(3) allows for the Authority to approve the rolling forward of capital expenditure, including a capital contribution made by a user or part of such a capital contribution, into the capital base on condition that the access arrangement contain a mechanism to prevent the service provider from benefiting, through increased revenue, from the user's contribution to the capital base.

DBP's Proposed Revisions

Opening Capital Base

118. DBP proposes an opening capital base for the 2011 to 2015 access arrangement period of $3,441.158 million (dollar values of 31 December 2010), derived by a roll-forward calculation over the 2005 to 2010 access arrangement period as indicated in Table 2. Within the roll-forward calculation, DBP has proposed adding to the capital base the capital expenditure financed by capital contributions.

Table 2 DBP's proposed calculation of the opening capital base for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[48]

Year ending 31 December	2005	2006	2007	2008	2009	2010
Capital Base at 1 January	1,943.616	1,892.965	1,902.069	2,265.330	2,843.884	2,811.153
plus						
Conforming Capital Expenditure	0.803	63.177	420.294	644.910	18.410	690.033
Forecast Capital Contributions	2.272	-	0.086	-	21.833	14.677
less						
Depreciation	53.726	54.073	57.119	66.356	72.973	74.705
Capital base at 31 December	**1,892.965**	**1,902.069**	**2,265.330**	**2,843.884**	**2,811.153**	**3,441.158**

119. DBP proposes that capital expenditure during the 2005 to 2010 access arrangement period consists of expenditure in the categories of pipelines, compression, metering and other depreciable assets. Capital expenditure is segregated into conforming capital expenditure financed by DBP (Table 3) and capital expenditure financed by capital contributions from users (Table 4).

Table 3 DBP's proposed conforming capital expenditure for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[49]

Year ending 31 December	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
Pipelines	0.758	3.044	250.867	517.147	0.175	450.680
Compression	-	56.518	167.090	121.930	9.787	171.963
Metering	-	0.057	-	-	0.078	0.050
Other depreciable assets	0.045	3.557	2.337	5.833	8.369	67.340
Non-depreciable assets	-	-	-	-	-	-
Total	**0.803**	**63.177**	**420.294**	**644.910**	**18.410**	**690.033**

48 DBNGP revised access arrangement information and tariff model of 12 April 2010. Dollar values of 31 December 2010 have been derived from values presented by DBP (in dollar values of 31 December 2009) with escalation for inflation according to changes in the "all groups eight capital cities" CPI.

49 DBNGP revised access arrangement information and tariff model of 12 April 2010.

Table 4 DBP's stated capital contributions for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[50]

Year ending 31 December	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
Pipelines	-	-	-	-	9.868	-
Compression	-	-	-	-	-	-
Metering	2.272	-	0.086	-	11.887	14.677
Other depreciable assets	-	-	-	-	0.077	-
Non-depreciable assets	-	-	-	-	-	-
Total	**2.272**	**-**	**0.086**	**0.000**	**21.833**	**14.677**

Projected Capital Base

120. DBP proposes projected capital base values for the 2011 to 2015 access arrangement as indicated in Table 5.

Table 5 DBP's calculation of the projected capital base for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[51]

Year	2011	2012	2013	2014	2015
Capital Base at 1 January	3,441.158	3,418.824	3,343.434	3,263.704	3,181.309
plus					
Forecast Conforming Capital Expenditure	71.972	18.450	15.804	15.034	15.331
Forecast Capital Contributions	0.235	2.726	1.479	-	-
less					
Forecast Depreciation	94.540	96.566	97.012	97.428	97.831
Forecast Asset Disposals	-	-	-	-	-
Capital Base at 31 December	**3,418.824**	**3,343.434**	**3,263.704**	**3,181.309**	**3,098.810**

121. DBP's proposed forecast of capital expenditure during the 2011 to 2015 access arrangement period is indicated in Table 6 (DBP financed conforming capital expenditure) and Table 7 (expenditure financed by capital contributions).

50 DBNGP revised access arrangement information and tariff model of 12 April 2010.

51 DBNGP revised access arrangement information and tariff model of 12 April 2010.

Table 6 DBP's forecast conforming capital expenditure for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[52]

Year ending 31 December	2011	2012	2013	2014	2015	Total
Pipelines	15.812	8.616	3.983	4.743	8.017	**41.171**
Compression	8.494	0.498	2.725	2.725	0.159	**14.602**
Metering	5.719	4.465	4.830	0.631	0.837	**16.482**
Other depreciable assets	41.947	4.871	4.265	6.934	6.318	**64.335**
Non-depreciable assets	-	-	-	-	-	**-**
Total	**71.972**	**18.450**	**15.804**	**15.034**	**15.331**	**136.591**

Table 7 DBP's forecast capital contributions for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[53]

Year ending 31 December	2011	2012	2013	2014	2015	Total
Pipelines	-	-	-	-	-	-
Compression	-	-	-	-	-	-
Metering	0.235	2.726	1.479	-	-	**4.440**
Other depreciable assets	-	-	-	-	-	-
Non-depreciable assets	-	-	-	-	-	-
Total	**0.235**	**2.726**	**1.479**	-	-	**4.440**

122. DBP indicates that there is no forecast value of assets to be disposed of during the 2011 to 2015 access arrangement period and that a capital redundancy mechanism, as provided for under rule 85 of the NGR, is not applicable under the proposed revised access arrangement.[54]

Substantiating Information for Conforming Capital Expenditure

123. DBP has provided the Authority with information in supporting submissions to justify its actual and forecast conforming capital expenditure.[55]

52 DBNGP revised access arrangement information and tariff model of 12 April 2010.

53 DBNGP revised access arrangement information and tariff model of 12 April 2010.

54 DBP, 1 April 2010, Proposed revised access arrangement, clause 1.6.

55 DBP, 14 April 2010, Confidential supporting submission #9: Justification of expansion related capital expenditure. DBP, 1 April 2010, Confidential supporting submission #10: Actual stay in business capital expenditure (2005 to 2010) justification and forecast stay in business capital expenditure (2011 to 2015). DBP, 14 April 2010, Confidential supporting submission #11: Forecast capital expenditure. Public versions of these submissions are available to interested parties.

Submissions

124. Several submissions made to the Authority on the proposed revised access arrangement made a general request for the Authority to scrutinise various elements of the roll-forward calculation for determining the capital base.

125. On actual capital expenditure in the 2005 to 2010 access arrangement period, concerns were raised in submissions on the following matters.

- Actual expenditure for the 2005 to 2010 access arrangement period being substantially greater than forecast for the period.[56]
- Whether future demand will be sufficient to justify the expansions undertaken during the 2005 to 2010 access arrangement period and whether all of the capital expenditure on expansion should be added to the capital base.[57]
- Whether the magnitude and timing of the expansions are reasonable given that the pipeline was expanded during a period of exceptionally high construction costs and during a period where there were significant concerns over future availability of gas for the domestic market, raising the issue of whether a prudent operator may well have deferred some of the expansions.[58]
- The contention of DBP that undertakings to the ACCC in relation to investment in expansion of the DBNGP comprise a regulatory obligation or requirement that is within the scope of rule 79(2)(c)(iii) of the NGR.[59]
- A lack of evidence provided by DBP to establish that the expenditure can be added to the capital base on the basis that the overall economic value of the expenditure is positive.[60]

126. On forecast capital expenditure for the 2011 to 2015 access arrangement period, concerns were raised in submissions over the following matters.

- An unusually large amount of forecast expenditure for 2011 in the category of “other depreciable assets”;[61]
- The limited capital expenditure forecast for the 2011 to 2015 access arrangement period in contrast to a program that has seen more than $1.8 billion spent in the 2005 to 2010 access arrangement period, which raises questions of –
  - is the level of expenditure sufficient to maintain the integrity of the DBNGP and reliability of supply? and
  - is the assumption that there will be no expansion of the DBNGP during the period 2011 to 2015 reasonable?[62]

56 Alinta Pty Limited, 9 July 2010, ERM Power, 7 July 2010; Newgen Power, 9 July 2010, Verve Energy, 9 July 2010.

57 Newgen, 9 July 2010.

58 ERM Power Pty Ltd, 7 July 2010, p. 3; NewGen Power, 9 July 2010.

59 Alinta Pty Limited, 9 July 2010; Verve Energy, 9 July 2010.

60 Verve Energy, 9 July 2010.

61 Wesfarmers Chemicals, Energy & Fertilisers, 9 July 2010.

62 Verve Energy, 9 July 2010.

127. On the treatment of capital contributions, concerns were raised in submissions over the following matters.

- Little explanatory information has been provided by DBP in relation to the capital contributions proposal, including the specifics of the funded capital expenditure, contributing agreement and shipper specific facilities charge.[63]
- A misalignment of the proposed treatment of capital contributions and the actual financial modelling undertaken by DBP.[64]
- Whether a grant of $88 million made by the Western Australian government to the owners of the DBNGP in the October 2004 Financial Assistance Agreement should be treated similarly to capital contributions by users, and excluded from revenue calculations in a clear and transparent manner.[65]

128. All of these matters are addressed below.

Considerations of the Authority

Overview of matters addressed by the Authority

129. The Authority has first addressed first the value of the opening capital base for the 2011 to 2015 access arrangement period and secondly the roll forward of the projected capital base over the 2011 to 2015 access arrangement period.

130. In assessing whether DBP's proposed opening capital base and projected capital base over the 2011 to 2015 access arrangement period meet the requirements of the NGR, the Authority has addressed the following matters.

- The calculation methods and the accuracy of financial calculations applied by DBP.
- The proposed conforming capital expenditure in the 2005 to 2010 access arrangement period, assessing whether DBP's proposed conforming capital expenditure meets the requirements for conforming capital expenditure in rule 79 of the NGR.
- The forecast conforming capital expenditure for the 2011 to 2015 access arrangement period, assessing DBP's forecast of conforming capital expenditure against the requirements for conforming capital expenditure in rule 79 of the NGR.
- The depreciation schedules applied by DBP and DBP's calculation of depreciation allowances.
- DBP's proposed treatment of capital contributions from users.

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63 Verve Energy, 9 July 2010.

64 Alinta Pty Limited, 9 July 2010.

65 Verve Energy, 9 July 2010.

Calculation Methods

131. The Authority has reviewed the calculation methods applied by DBP in determining the proposed capital base values and identified elements of the calculation method that require amendment. These elements comprise:

- the measure of inflation applied in escalation of capital base values;
- the values of capital expenditure applied in a re-calculation by DBP of the roll-forward of the capital base from 31 December 1999.

132. The Authority's considerations in respect of each of these elements of the capital-base calculations are set out as follows.

Inflation Escalation

133. DBP has calculated the opening capital base for the 2011 to 2015 access arrangement period by re-creating a roll-forward calculation of capital base values from the initial capital base for the DBNGP that was established for the pipeline as it existed at 31 December 1999 and in dollar values of that date. In re-creating this roll-forward calculation, DBP has included escalation of the capital base values for inflation so that the capital base is expressed in dollar values of 31 December 2009. In escalating values of the capital base for inflation, DBP has applied escalation factors derived from the "all groups Perth" CPI.

134. There are two problems with the inflation escalation applied by DBP.

135. First, DBP has applied the escalation factors derived from the "all-groups Perth" CPI to re-calculate capital base values from the value of the initial capital base determined as at 31 December 1999. This results in DBP having, effectively, determined a real value of the capital base at the commencement of the 2005 to 2010 access arrangement period that is different to (and larger than) the value that was approved by the Authority for that access arrangement period, which was calculated using escalation factors derived from the "all-groups eight capital cities" CPI.

136. Secondly, and as already addressed in this draft decision (paragraphs 105 and 106), the Authority has determined that the inflation escalation of financial parameters from the 2005 to 2010 access arrangement period to the commencement of the 2011 to 2015 access arrangement period should be undertaken using escalation factors derived from the "all-groups eight capital cities" CPI.

137. Correction of these two matters, but leaving all other elements of DBP's capital base calculation unchanged, results in a lower value of the opening capital base for the 2011 to 2015 access arrangement period than proposed by DBP by an amount of approximately $9 million (dollar values of 31 December 2010).

Values of capital expenditure applied in recalculation from the capital base from 31 December 1999

138. In re-calculating capital base values from the value of the initial capital base determined at the date of 31 December 1999, DBP has applied a slightly different value of capital expenditure for compression assets in 2000 than was applied in the calculation of the capital base value at 31 December 2004 that was approved by the Authority as the capital base at the commencement of the 2005 to 2010 access arrangement period.

139. The difference is immaterial in relation to the value of the capital base (approximately $5,000), but the Authority has in any case used the correct value of the capital base at the start of the 2005 to 2010 access arrangement period as the basis for the roll-forward calculation of the capital base.

Capital Expenditure in the 2005 to 2010 Access Arrangement Period

Proposed Additions of Conforming Capital Expenditure to the Capital Base

140. DBP classifies capital expenditure into two categories:

- expansion expenditure; and
- stay-in-business capital expenditure.

141. DBP indicates that expansion expenditure in the 2005 to 2010 access arrangement period comprised expenditure for three stages of expansion: stages 4, 5A and 5B. The capital works and pipeline assets associated with each of these three stages of expansion are described in information provided by DBP to the Authority.[66] The capital expenditure on expansion is indicated in Table 8 (dollar values of 31 December 2010).

66 DBP, 1 April 2010, Submission #9, section 5.

Table 8 DBP's stated expansion capital expenditure for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[67]

Year	2005	2006	2007	2008	2009	2010
Expansion Stage 4						
Pipeline	-	-	249.734	-	-	-
Compression	-	58.972	166.960	-	9.787	-
Metering	-	-	-	-	-	-
Other depreciable	-	-	-	-	1.097	-
Non depreciable	-	-	-	-	-	-
Total	-	58.972	416.694	-	10.884	-
Expansion Stage 5A						
Pipeline	-	-	-	517.157	-	-
Compression	-	-	-	122.785	-	-
Other	-	-	-	-	-	-
Other depreciable	-	-	-	1.509	-	-
Non depreciable	-	-	-	-	-	-
Total	-	-	-	641.452	-	-
Expansion Stage 5B						
Pipeline	-	-	-	-	-	450.000
Compression	-	-	-	-	-	155.000
Other	-	-	-	-	-	-
Other depreciable	-	-	-	-	-	29.900
Non depreciable	-	-	-	-	-	-
Total	-	-	-	-	-	634.900
Linepack					4.45	
Total	-	**58.972**	**416.694**	**641.452**	**15.334**	**634.900**

67 DBP, 1 April 2010, Submission #9, paragraph 1.13.

142. DBP indicates that the investment in expansion of the DBNGP was undertaken to:

- provide an expansion in capacity (stage 4 expansion) to meet expansion commitments to users that lodged access requests prior to completion of the sale of the DBNGP in October 2004, in accordance with obligations under clause 9 of schedule 1 of the Financial Assistance Agreement between the Western Australian Government and buyers of the DBNGP, and obligations under a contract with Alcoa (Alcoa Exempt Contract); and
- provide expansions in capacity (stage 5A and 5B expansions) to meet capacity expansion requests for users that hold a "standard shipper contract" with DBP.

143. In addition to the values of investment in expansion indicated above, DBP proposes that the conforming expansion expenditure should include an amount of $19.96 million (dollar values of 31 December 2010)[68] relating to the lease by DBP of part of the capacity of the Burrup Extension Pipeline ("BEP Capacity"), which is owned by Epic Energy, although DBP has indicated to the Authority that this value was excluded by error from the capital base calculation of the proposed access arrangement.[69] DBP indicates that the BEP parallels the DBNGP for the first 23 km from the North West Shelf Domgas Plant to Mainline Valve No.7. DBP indicates that it has entered into a lease of 150 TJ/day of capacity of the BEP for a period of 20 years, with options to expand the leased capacity to 400 TJ/day and to extend the term of the lease by a further 40 years.[70]

144. DBP contends that the capital expenditure for expansion of the DBNGP meets the criteria of rule 79 for conforming capital expenditure on the grounds that:

- processes of planning, procurement and management adopted for the expansion investments provide sufficient basis to conclude that the capital expenditure for expansion complies with the prudence and efficiency requirement of rule 79(1)(a);
- the expansion investment was undertaken to comply with undertakings to the Australian Competition and Consumer Commission under section 87B of the *Trade Practices Act 1974* to expand the capacity of the DBNGP, which constitutes a regulatory obligation or requirement within the meaning of rule 79(2)(c)(iii); and
- the overall economic value of the capital expenditure is positive.

145. DBP indicates that stay-in-business capital expenditure in the 2005 to 2010 access arrangement period comprised expenditure of $73.382 million (dollar values of 31 December 2010).[71] The stay-in-business capital expenditure is set out in Table 9. The capital works that comprise the stay-in-business capital expenditure are described in information provided by DBP to the Authority.[72]

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68 DBP, 1 April 2010, Submission #9, section 16; the value stated in dollar values of 2010 corresponds to the value indicated in DBP's submission of $19.04 million in 2008 dollar values.

69 DBP, 1 April 2010, Submission #9, section 16.

70 DBP, 1 April 2010, Submission #9, section 16.

71 DBP, 1 April 2010, Submission #10, paragraph 4.1.

72 DBP, 1 April 2010, Submission #10, sections 5, 6.

Table 9 DBP's stated stay-in-business capital expenditure for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[73]

Year	2005	2006	2007	2008	2009	2010
Stay-in-business capital expenditure	0.793	4.130	3.368	3.474	7.525	54.092

146. Information provided by DBP in support of the stay-in-business capital expenditure comprises a description of planning, management and contracting practices for the capital expenditure, an indication that part of the stay-in-business capital expenditure is in accordance with the safety case for the pipeline, and information on the details and reasons for particular line-items of expenditure.[74]

147. The Authority has addressed the proposed values of capital expenditure to be added to the capital base by consideration of:

- the scope of capital expenditure to be added to the capital base, addressing in particular the proposed capital expenditure comprising the cost of the lease of the BEP Capacity, capital expenditure for construction of a lateral pipeline at Kemerton, and capital expenditure on linepack gas;
- information provided to verify values of capital expenditure;
- whether capital expenditure conforms with the prudence and efficiency criteria of rule 79(1)(a); and
- whether capital expenditure is justified on the grounds of rule 79(2).

148. These matters are addressed in turn, below.

Scope of Capital Expenditure to be added to the Capital Base

149. The Authority has addressed three matters relating to the scope of capital expenditure to be added to the capital base:

- treatment of the cost of the lease of BEP Capacity as capital expenditure;
- capital expenditure on a lateral pipeline to the Kemerton industrial area (Kemerton Power Station Lateral); and
- capital expenditure on linepack gas.

150. DBP proposes that capital expenditure to be added to the capital base should include expenditure incurred in the lease of BEP Capacity ("BEP Capacity") and for construction of a lateral pipeline from the DBNGP to the Kemerton industrial area near Bunbury.

BEP Capacity

151. The proposed capital expenditure for the BEP Capacity comprises the present value of forecast lease payments to be made by DBP in respect of DBP's lease of an amount of capacity in the BEP, which is owned by Epic Energy.

73 DBP, 1 April 2010, Submission #10, paragraph 4.1.

74 DBP, 1 April 2010, Submission #10, sections 3, 7.

152. DBP submits that the lease arrangement is in the nature of a finance lease and is consistent with economic ownership the BEP Capacity. As such, DBP contends that the cost of the lease is in the nature of capital expenditure. DBP proposes that the cost of the BEP Capacity should be added to the capital base in 2010, with the value of capital expenditure equal to $19.96 million (dollar values of 31 December 2010), determined as the present value of the lease fee.[75]

153. In assessing whether the cost of leasing the BEP Capacity constitutes capital expenditure incurred in the 2005 to 2010 access arrangement period, the Authority has considered:

- whether, or under what circumstances, the costs of a lease may constitute capital expenditure for the purposes of the NGR and, if so, whether the nature of the lease arrangement for the BEP Capacity is such that the cost of the lease constitutes capital expenditure within the meaning of the NGR; and
- whether the cost of the lease of the BEP capacity (as the present value of lease payments) can be treated as capital expenditure having been incurred in the 2005 to 2010 access arrangement period or whether it should be treated as being incurred at a different time or times.

154. The Authority is of the view that the costs of a lease arrangement may constitute capital expenditure for the purposes of the NGR if the lease is in the nature of a finance lease. In coming to this view, the Authority has had regard to the following matters.

- Capital expenditure is defined in rule 69 of the NGR as costs and expenditure of a capital nature incurred to provide, or in providing, pipeline services.
- In considering whether the costs of a lease constitute costs and expenditure of a capital nature, the Authority has had regard to accounting standards of the Australian Accounting Standards Board. Accounting standard AASB 117 requires that the value of an asset leased under a financial lease be treated as a capital asset for accounting purposes, with the value of the asset being determined as the lesser of the market value of the asset or the present value of the lease payments.[76]

155. The Authority is satisfied from the terms of the lease and the supporting information provided by DBP that the lease is in the nature of a finance lease and that the cost of the lease of the BEP Capacity should be treated as capital expenditure. DBP has deliberately structured the lease of the BEP Capacity as a finance lease in accordance with the definition and criteria for a finance lease under accounting standard AASB 117 with the intent of having the costs of the lease treated as capital expenditure for regulatory purposes.[77]

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[75] DBP, 1 April 2010, Submission #9, section 16; the value stated in dollar values of 2010 corresponds to the value indicated in DBP's submission of $19.04 million in 2008 dollar values.

[76] AASB 117, paragraph 20.

[77] DBP Holdings Pty Ltd, 23 May 2006, Board Agenda Item 22.3c 'BEP Strategy Update' (DBP Submission #37 Attachment 2); Dampier Bunbury Pipeline and Alinta, 5 September 2007, Technical Accounting Paper BEP – Lease Accounting Issues (DBP Submission #37 Attachment 44); Dampier Bunbury Pipeline and Alinta, 5 September 2007, Technical Accounting Paper Burrup Extension Pipeline ("BEP") – Lease Accounting Issues (DBP Submission #37 Attachment 45).

156. On the matter of whether the costs of the lease can be considered capital expenditure in the 2005 to 2010 access arrangement period, the Authority observes that, at the time that DBP submitted the proposed revised access arrangement to the Authority, the lease agreement had not come into effect due to a number of conditions precedent not having been satisfied. In these circumstances, the Authority does not accept that expenditure in respect of lease payments for the BEP has been incurred by DBP, nor is forecast to be incurred, in the 2005 to 2010 access arrangement period. However, DBP has since advised the Authority that the conditions precedent have been satisfied and that the lease agreement came into effect in December 2010.[78] On this basis, the lease costs may appropriately be regarded as capital expenditure in the 2005 to 2010 access arrangement period.

157. Given that the Authority is satisfied that the costs of the lease may be added to the capital base, the Authority has considered the value of these costs proposed by DBP.

158. In assessing the cost of lease payments against the prudence and efficiency criteria of rule 79(1)(a), the Authority has considered:

- the terms of the lease;
- whether the lease of the BEP Capacity is the most cost-effective means of achieving the additional capacity in the DBNGP for provision of services; and
- the derivation of the cost of the lease.

159. DBP indicates the BEP is an underutilised pipeline that parallels the first 23 km of the DBNGP. The BEP has an inlet point at the North West Shelf Joint Venture Domgas Plant that is separate from the inlet point to the DBNGP, and is interconnected with the DBP by an interconnection with the original DBNGP pipeline (at main line valve 7) and by direct connection to a looped section of the DBNGP between the BEP and compressor station CS1, constructed as part of expansion stage 5B.[79]

160. The lease agreement for the BEP Capacity comprises a lease between:

- Epic Energy (Pilbara Pipeline) Pty Ltd, as the lessor; and
- DBNGP (WA) Nominees Pty Ltd and Epic Energy (Pilbara Pipeline) Pty Ltd, as the lessees.[80]

161. Principal terms of the lease agreement are that:

- the term of the lease is 20 years with an option of the lessees to extend the term for a further 40 years;
- DBP has a 45.5 per cent interest in the lease, corresponding to an interest in 150 TJ/day of BEP Capacity, with an option (exercisable before 31 December 2011) to increase this interest to 69.9 per cent, corresponding to an interest in 230 TJ/day of BEP Capacity; and

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78 DBP, 6 January 2010, submission #40.

79 DBP presentation to the Economic Regulation Authority, December 2010, slide 7.

80 DBP, August 2010, Submission # 27, Appendix 1: BEP Lease Agreement.

- notwithstanding that DBP only has a part interest in the lease, DBP has responsibility for operation, routine maintenance, major works and non-routine maintenance of the BEP, and bears the whole of the associated operating and/or capital costs.[81]

162. On the question of whether the lease of the BEP Capacity is the most cost effective option for increasing capacity of the DBNGP, DBP indicates that the lease of the BEP Capacity forms a part of the stage 5B expansion of the DBNGP and that two other options were considered for the configuration of the northern part of the pipeline system from which lease of the BEP Capacity was selected:
    - replication of the DBNGP through looping from inlet point I1-01 (Option 1); and
    - addition of additional compression at CS1 to allow for draw down of additional gas and pressure from inlet point I1-01 and then to commence further looping of the pipeline downstream of CS1 (Option 3).[82]

163. DBP indicates that Option 1 was rejected for reasons of:
    - cost, with an estimated capital cost of $60 million; and
    - expected difficulties in obtaining environmental and heritage approvals for the new pipeline construction, and consequent risks of a longer time frame for construction.[83]

164. DBP indicates that Option 3 was rejected for reasons of:
    - operational difficulties and risks that would arise from additional compression at CS1; and
    - additional fuel gas requirements, potential difficulties in securing additional fuel gas and a high price for additional fuel gas.[84]

165. DBP's submissions on the consideration of alternatives to the lease of the BEP capacity are supported by evidence provided to the Authority by DBP comprising Board papers and Board minutes dealing with the consideration of options, the strategy for procurement of the BEP Capacity by a lease arrangement and the terms of the lease.[85]

166. The cost to DBP of the lease of the BEP Capacity comprises a monthly rent payment calculated to reflect that DBP has a share of use of the total capacity of the BEP and the capital and operating costs of operating and maintaining the whole of the BEP.

167. The monthly rent payment constitutes a 49 per cent share of a monthly rental charge. The monthly charge is determined from:
    - a base rent amount [redacted]; and

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81 DBP, August 2010, Submission # 27, Appendix 1: BEP Lease Agreement.

82 DBP Submission #27, p. 8.

83 DBP Submission #27, p. 9.

84 DBP Submission #27, p. 8.

85 DBP Submission #37.

- annual escalation of the base rent amount at a rate of 67 per cent of the rate of change in the all-groups Perth CPI (using September quarter CPI values).[86]

168. DBP has not provided information to enable the Authority to identify forecast operating and capital costs for the BEP, which the Authority presumes are included in the forecasts of capital and operating expenditure for the entire DBNGP for the 2011 to 2015 access arrangement period.

169. DBP has indicated to the Authority that the cost to DBP for the BEP Capacity is not based on a bottom-up calculation of costs of the BEP asset but rather is an outcome of a commercial negotiation with the owners of the BEP, with these negotiations affected by DBP knowing the cost of alternative options to a lease of the BEP Capacity and the owners of the BEP motivated to gain additional utilisation for the BEP.[87]

170. DBP's attributed capital cost of the lease of the BEP Capacity is calculated as a present value of rent charges over a 20 year lease period. In documentation submitted with the proposed revised access arrangement, DBP proposed a value of $19.04 million in dollar values of 2008 ($19.96 million in dollar values of 31 December 2010). DBP has subsequently submitted a revised value to the Authority of $22.672 million at 1 December 2010 based on:

- the term of the contract being from 1 December 2010 to 30 November 2030;
- DBP's share of the monthly rent charge of 49 per cent;
- an assumed annual inflation rate (for escalation of rent charges) of 2.5 per cent; and
- a nominal annual discount rate [redacted] with monthly discounting of rent charges.[88]

171. The Authority is not satisfied that the capital cost ascribed to the lease of the BEP Capacity has been appropriately determined. The Authority considers that the capital costs should be determined in accordance with Australian Accounting Standard AASB 117, paragraph 20 of which requires that:

> At the commencement of the lease term, lessees shall recognise finance leases as assets and liabilities in their statements of financial position at amounts equal to the fair value of the leased property or, if lower, the present value of the minimum lease payments, each determined at the inception of the lease. The discount rate to be used in calculating the present value of the minimum lease payments is the interest rate implicit in the lease, if this is practicable to determine; if not, the lessee's incremental borrowing rate shall be used. Any initial direct costs of the lessee are added to the amount recognised as an asset.

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86 DBP, August 2010, Submission # 27, Appendix 1: BEP Lease Agreement.

87 DBP, Submission # 34, Attachment 4 slide 14.

88 DBP, Submission #34, Attachment 2.

172. The matter of concern to the Authority in DBP's determination of the capital cost ascribed to the lease of the BEP Capacity is the discount rate applied in calculating the present value of the lease payments. DBP has not provided the Authority with any justification for the discount rate [redacted]. As there is no interest rate implicit in the lease, AASB 117 would require that the lessee's incremental borrowing rate be used. The Authority considers that the rate that should be applied in valuing the lease costs for regulatory purposes should be the incremental cost of funds, which is the nominal pre-tax weighted average cost of capital for the DBNGP. This has been estimated by the Authority to be 10.00 per cent (refer to paragraph 756 of this draft decision).

173. The Authority has re-calculated the capital cost ascribed to the lease of the BEP capacity as $17.274 million (dollar values of 31 December 2010) based on:

- the term of the contract being from 1 January 2011 to 31 December 2030;
- rent charges as per the lease agreement, adjusted for actual CPI values to September 2010 and using forecast CPI values based on a forecast inflation rate of 2.65 per cent;
- a nominal annual discount rate of 10.00 per cent, with annual discounting of rent charges, consistent with an implicit assumption in financial calculations for the draft decision (and as applied by DBP) that all costs are incurred on the last day of each year.

174. Taking the above matters into account, the Authority is satisfied that the lease of the BEP Capacity is an efficient means of increasing the capacity of the DBNGP, but the Authority is not satisfied the value of lease payments proposed by DBP to be added to the capital base conforms to the prudence and efficiency criteria of rule 79(1)(a). The Authority considers that the value that conforms with these criteria is $17.274 million (dollar values of 31 December 2010).

175. In assessing whether the capital expenditure of the BEP Capacity is justifiable on one of the grounds of rule 79(2) of the NGR, the Authority has applied the same reasoning as addressed for capital expenditure on expansion in the 2005 to 2010 access arrangement period in considering the overall economic value of the investment (paragraphs 266 to 269 of this draft decision). Accordingly, the Authority is satisfied that the capital expenditure is justified under rule 79(2)(a) in that the overall economic value of the expenditure is positive.

176. The Authority is therefore satisfied that capital expenditure of $17.274 million (dollar values of 31 December 2010) for the BEP capacity is conforming capital expenditure. For the purposes of this draft decision, the Authority has added this forecast to the projected capital base in 2010.

177. An additional matter related to the BEP Capacity is whether the whole of the operating and capital costs incurred by DBP in operation and maintenance of the BEP should be included in the forecasts of costs used to calculate total revenue given that DBP leases only part of the capacity of the BEP for the provision of transmission services via the DBNGP. In forecasts of costs, DBP has not separately identified operating and capital expenditure associated with the BEP, but the Authority presumes that this expenditure is included in the forecasts.

178. The Authority takes the view that DBP's liability for these costs is part of the overall cost of leasing the BEP Capacity and may have been considered in negotiation of the rent payable under the lease. As such, the Authority does not for the purposes of this draft decision require amendment to the forecasts of capital and operating costs to ensure that only a part of the capital and operating costs for operation and maintenance of the BEP should be included in total revenue, with that part reflecting DBP's proportional interest in the lease for the BEP Capacity. However, the Authority will give further consideration to this matter prior to the final decision.

Kemerton Power Station Lateral

179. The Kemerton Power Station lateral comprises a pipeline and meter station constructed in 2005 and 2006. DBP indicates the expenditure was incurred mainly (96 per cent) in 2005.[89] DBP indicates that this expenditure was entirely financed by a capital contribution from one party with the amount of capital contributions included in DBP's stated value of contributions for 2009.[90] As an element of its access arrangement, DBP has proposed that conforming capital expenditure that is financed by capital contributions from users be added to the capital base, but the values of a return on the capital expenditure and depreciation be excluded from the total revenue to be recovered from reference services (refer to paragraph 293 and following of this draft decision). The Authority, consistent with its requirement elsewhere in this draft decision for independently audited values of assets that are to be added to the capital base, will require the same verification for assets associated with capital contributions if they are to be included in the capital base.

180. Subject to implementation of this treatment of capital expenditure financed by capital contributions, the Authority considers that capital expenditure for the Kemerton lateral may appropriately be added to the capital base.

Linepack Gas

181. DBP has proposed that a cost of $4.45 million (dollar values of 2010) for line pack gas in 2009 be treated as capital expenditure. For the purposes of calculating depreciation allowances, DBP has categorised linepack gas as an "other depreciable asset".

182. The Authority considers that linepack gas should not be treated as a depreciable asset as it is an asset that is not used or degraded over time in the delivery of pipeline services. The Authority considers that line pack gas should be treated as an "other non-depreciable asset".

Verification of Capital Expenditure

183. During the course of the Authority's assessment of the proposed revised access arrangement, DBP has provided to the Authority audit reports on capital expenditure for the stage 4 and stage 5A expansions and an interim audit report of capital expenditure for the stage 5A expansion.

89 DBP, 6 September 2010, Submission #31.

90 DBP, 6 September 2010, Submission #31.

184. There are differences between the values of expansion expenditure as stated by DBP and the values determined by audits, with audited values being (in total) $23.314 million (nominal) less than the values of expenditure stated by DBP (Table 10).

Table 10 Audited and stated values of capital expenditure for the stage 4 and stage 5A expansions (nominal dollar values)

Expansion Stage 4						
Stated value[91]	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
		52.702	383.407		10.604	
Total stated value						446.712
Total audited value[92]						417.683
Difference						**29.025**
Expansion Stage 5A						
Stated value[93]	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
				611.962		14.000
Total stated value						625.962
Total audited value[94]						625.330
Difference						**0.632**
Expansion Stage 5B						
Stated value[95]	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
						620.900
Total stated value						620.900
Total (interim) audited						627.557
Difference						**-7.343**

185. The Authority also observes that there are other discrepancies in values of capital expenditure provided by DBP; in particular values of stay-in-business capital expenditure stated by DBP exceed total values of stated capital expenditure in some asset classes in some years (Table 11). The Authority considers that this discrepancy calls into question the accuracy and reliability of DBP's stated values of capital expenditure, and the division of expenditure between the categories of expansion expenditure and stay-in-business expenditure.

[91] DBP Submission #9, paragraph 1.13.

[92] DBP Submission #9, Attachment 4, State 4 Capex Audits (comprising reports from BDO dated between 17 July 2006 and 29 March 2007).

[93] DBP Submission #9, paragraph 1.13.

[94] DBP Submission #41 and attached report of BDO Audit WA Pty Ltd dated 29 November 2010.

[95] DBP Submission #9, paragraph 1.13. This is the value stated by DBP in supporting documents for the proposed access arrangement revisions. The interim audit report for stage 5A indicated stated transactions by DBP to December 2010 of $644.303 million (nominal).

[96] DBP Submission #41 and attached report of BDO Audit WA Pty Ltd dated 20 December 2010.

Table 11 Discrepancies between stated values of total capital expenditure and stay-in-business capital expenditure (nominal dollar values)[97]

Year	2005	2006	2007	2008	2009	2010
Total capital expenditure						
Pipeline	0.648	2.717	230.699	493.382	9.784	450.000
Compression	0.000	50.449	153.656	116.327	9.534	171.703
Metering	1.943	0.051	0.079	-	11.656	14.705
Other	0.038	3.175	2.149	5.565	8.227	67.239
Total	**2.630**	**56.393**	**386.584**	**615.274**	**39.201**	**703.647**
Stay-in-business capital expenditure						
Pipeline	0.648	0.094	-	-	-	0.300
Compression	-	0.076	0.690	2.259	10.309	13.130
Metering	-	0.051	-	-	0.076	0.050
Other	0.038	3.849	3.098	3.539	2.399	38.280
Total	**0.686**	**4.070**	**3.788**	**5.798**	**12.785**	**51.760**
Difference (implied expansion capital expenditure)						
Pipeline	-	2.623	230.699	493.382	9.784	449.700
Compression	-	50.373	152.966	114.068	-0.775	158.573
Metering	1.943	-	0.079	-	11.580	14.655
Other	-	-0.674	-0.949	2.026	5.828	28.959
Total	**1.944**	**52.323**	**382.796**	**609.476**	**26.417**	**651.887**

186. In view of the differences between stated and audited values of expenditure for the stages 4 and 5A expansions and the discrepancies in statements of capital expenditure, the Authority will approve only the addition of audited values of capital expenditure. DBP has already provided audited values of expenditure for the stage 4 and 5A expansions. DBP will need to provide final audited statements of capital expenditure for the stage 5B expansion (for costs incurred up to 31 December 2010) and stay-in-business capital expenditure before a final determination on the value of the capital base at the commencement of the 2011 to 2015 access arrangement period.

187. For the purposes of this draft decision, the Authority has amended the value of capital expenditure in the 2005 to 2010 access arrangement period to reflect audited values of expenditure for the stage 4 and 5A expansions and interim audited values of expenditure for the stage 5B expansion, as indicated in Table 10.

[97] DBP AAI, Reference Tariff Model, DBP Submission 10 and 11 and DBP Submission14 and 17.

Prudence and Efficiency

188. Rule 79(1)(a) of the NGR requires that conforming capital expenditure must be 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 of providing services. For simplicity of reporting, the Authority refers in this decision to the requirement of rule 79(1)(a) as the "prudence and efficiency" requirement.

189. DBP contends that the enhancement capital expenditure in the 2005 to 2010 access arrangement period meets the prudence and efficiency requirement of rule 79 on the grounds that processes of planning, management and procurement provide a sufficient basis to conclude that the capital expenditure meets this requirement. DBP does not make any specific contention about stay-in-business capital expenditure meeting the prudence and efficiency requirement, although a provision by DBP of a description of planning, management and contracting practices for this capital expenditure implies a contention that expenditure meets the prudence and efficiency requirement on the basis of these practices.

190. In assessing whether the capital expenditure of the 2005 to 2010 access arrangement period meets the prudence and efficiency requirement the Authority has given consideration to:

- commercial incentives for DBP to be prudent and efficient in capital expenditures;
- a comparison of actual capital expenditure for the 2005 to 2010 access arrangement period with the values of expenditure forecast for that period and taken into account by the Authority for the purposes of setting reference tariffs for the period;
- expert engineering advice on the scope of capital projects and the planning, management and procurement processes applied by DBP in undertaking the capital projects; and
- costs incurred by DBP as "project management fees" and "project management retainer fees".

191. Each of these matters is addressed in turn, below. Having addressed these matters, the Authority is of the view that, subject to corrections for the scope and verification of capital expenditure as set out above, the capital expenditure of the 2005 to 2010 access arrangement period meets the prudence and efficiency requirements of rule 79(1)(a) of the NGR.

Commercial Incentives

192. Under the regulatory regime established by the NRL and NGR, a service provider typically has some commercial incentive for prudence and efficiency in capital expenditure. This incentive arises from:

- the ability of the service provider to retain the benefit of out-performing forecasts of capital expenditure that are taken into account in the determination of reference tariffs (at least to the extent that users of the pipeline are paying tariffs at the level of the reference tariffs);

- the inability of the service provider to earn, during a single access arrangement period, a rate of return on any capital expenditure in excess of the forecast expenditure (again, at least to the extent that users of the pipeline are paying tariffs at the level of the reference tariffs); and
- a risk to the service provider that the regulator under the NGL will determine part of capital expenditure to not meet the prudence and efficiency requirement of rule 79(1)(a) of the NGR and not add this part of capital expenditure to the capital base for the pipeline, preventing the service provider from earning a return on and of this amount through reference tariffs in the future.

193. With users of the DBNGP not currently paying tariffs at the level of the reference tariff established under the access arrangement, and not expected to do so for the course of the 2010 to 2015 access arrangement period,[98] the first two of these commercial incentives for prudence and efficiency in capital expenditure do not apply. The third element of does apply, as it is intended that current gas transmission contracts will revert to the regulated reference tariff in 2016, and the level of capital recovery in the reference tariff will be determined by the extent to which capital expenditure can be added to the capital base.

194. Notwithstanding that users of the DBNGP do not currently pay a reference tariff, the terms of the SSC for the provision of pipeline services would provide commercial incentives for prudence and efficiency in capital expenditure. The Authority considers that these incentives may actually be stronger than the incentives under the regulatory regime established by the NRL and NGR.

195. Under the SSC with users, tariffs for gas transmission have been established independently of the regulated tariffs or price controls established under the access arrangement and will remain so until at least 2016.[99] The tariffs established under the SSC are fixed with the exception of:

- escalation for inflation;[100]
- changes in taxation that are able to be passed through in changes to tariffs;[101] and
- adjustments (increases or decreases) in respect of certain amounts of expansion capital expenditure, calculated as a rate of return on a difference between actual expansion costs and certain benchmarks of expansion costs specified in the standard shipper contract.[102]

196. There is no provision under the SSC for tariffs to vary to recover a depreciation allowance for amounts of expansion capital expenditure in excess of benchmark amounts of expenditure, nor for tariffs to vary with levels of stay-in-business capital expenditure.

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[98] DBP, Standard Shipper Contract clause 20.5(d).

[99] DBP, Standard Shipper Contract clause 20.5(d).

[100] DBP, Standard Shipper Contract clause 20.5(c).

[101] DBP, Standard Shipper Contract clause 20.7.

[102] DBP, Standard Shipper Contract clause 20.8.

197. The Authority considers that the nature of the tariff arrangements under the SSC provide strong commercial incentives for DBP to be prudent and efficient in its capital expenditure for reasons of:

- the exposure of DBP to cost overruns on expansion projects for at least the period to 2016 as DBP will ultimately forego recovery of some depreciation allowances on the expansion capital expenditure when tariffs revert to regulated tariffs under the access arrangement, albeit DBP is able to adjust tariffs under the SSC to recover a rate of return on excess expansion costs over benchmark costs; and
- the inability of DBP to have stay-in-business capital expenditure reflected in changes to tariffs under the SSC until at least 2016.

Comparison of forecast and actual expenditure

198. A comparison of forecast and actual expenditure for the 2005 to 2010 access arrangement period is shown in Table 12.

Table 12 DBP's forecast and actual capital expenditures for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)

Year	2005	2006	2007	2008	2009	2010
Forecast Expenditure						
Pipeline	5.344	6.821	301.950	325.382	99.260	171.735
Compression	4.385	81.697	139.328	47.996	0.487	0.731
Metering	1.340	1.462	0.183	-	-	-
Other depreciable	4.763	3.776	1.888	6.505	7.735	7.175
Other non-depreciable	-	-	-	-	-	-
Total	**15.832**	**93.756**	**443.348**	**379.882**	**107.483**	**179.642**
Actual Expenditure						
Pipeline	0.749	3.041	250.728	517.160	10.043	450.000
Compression	-	56.451	166.997	121.934	9.787	171.703
Metering	2.245	0.057	0.086	-	11.966	14.705
Other depreciable	0.044	3.553	2.336	5.833	8.446	67.239
Other non-depreciable	-	-	-	-	-	-
Total	**3.039**	**63.102**	**420.147**	**644.926**	**40.242**	**703.647**
Difference						
Pipeline	-4.595	-3.781	-51.222	191.778	-89.217	278.265
Compression	-4.385	-25.245	27.669	73.938	9.300	170.972
Metering	0.906	-1.405	-0.097	-	11.966	14.705
Other depreciable	-4.719	-0.223	0.448	-0.672	0.710	60.063
Other non-depreciable	-	-	-	-	-	-
Total	**-12.793**	**-30.654**	**-23.201**	**265.043**	**-67.241**	**524.005**

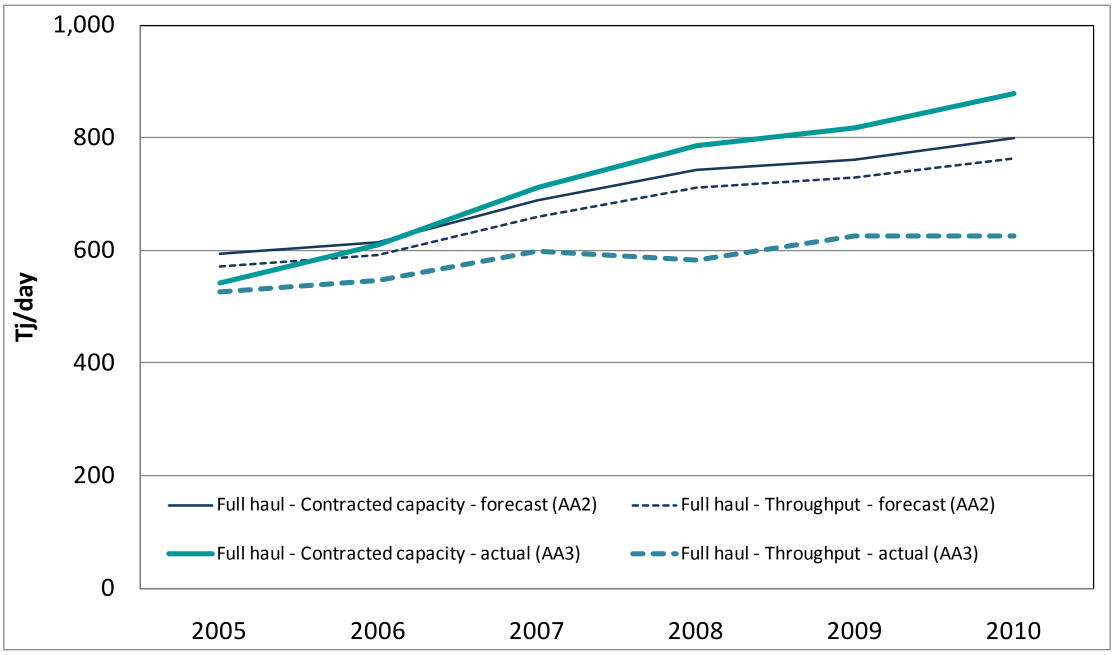
199. DBP provides the following reasons for the differences in forecast and actual capital expenditure for pipeline expansions.[103]

- Transmission quantities for expansion stages 5A and 5B were not finally determined until after the access arrangement for the 2005 to 2010 had been approved and were higher than the forecasts of demand that underpinned the forecasts of capital expenditure.
- The configuration of expansion works differed from the design underpinning the forecasts of capital expenditure.
- Unit rates for components of expansion works, such as looping construction rates and costs of compressor units, differed from the unit rates underpinning the forecasts of capital expenditure. Higher unit rates for costs are largely attributed to the effect of the mining boom in Western Australia on costs of steel and labour.

200. DBP indicates that the differences in forecast and actual stay-in-business capital expenditure resulted from the circumstances of the change in ownership of the DBNGP in 2005 and a compromised ability to make an accurate forecast at the time, and the major expansions that have occurred that have contributed to the need for stay-in business capital expenditure.[104]

201. The Authority observes from data provided by DBP that actual contracted capacity in the DBP during the later part of the 2005 to 2010 access arrangement period has exceeded the forecast for that period (Figure 2).

Figure 2: Actual and forecast contracted capacity and throughput for the 2005 to 2010 access arrangement period



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[103] DBP Submission #9, p19.

[104] DBP Submission #10, p19.

202. Taking into account the difference between forecast and actual contracted capacity in the DBNGP in the 2005 to 2010 access arrangement period, the Authority accepts the DBP's contention that differences between forecast and actual demand for services for the 2005 to 2010 access arrangement contributed to differences between forecast and actual capital expenditure. Accordingly, the Authority considers that differences between forecast and actual capital expenditure, while necessary to understand the revision proposal, do not inform an assessment of the prudence and efficiency of that expenditure in this case.

Expert Engineering Advice

203. The Authority has obtained advice from Halcrow Pacific Pty Ltd and Zincara Pty Ltd ("Halcrow & Zincara") on whether the capital expenditure in the 2005 to 2010 access arrangement period meets the prudence and efficiency requirement of rule 79(1)(a).[105]

204. For the expansion capital expenditure Halcrow & Zincara assessed the prudence and efficiency of the expenditure by consideration of the planning, management and contracting processes for each of expansion stages 4, 5A and 5B. From this assessment, Halcrow and Zincara concluded that the expansion capital expenditure for the 2005 to 2010 access arrangement period meets the prudence and efficiency requirement of rule 79(1)(a) for reasons that:

- the expansion program implemented by DBP (i.e. expansion stages 4, 5A and 5B) has been properly planned in a manner consistent with that expected of a gas transmission pipeline operator;
- the adopted form of expansion represents the most efficient means of increasing capacity to meet the identified demand;
- the program has been appropriately staged;
- contractor engagement has been market tested, whilst at the same time leveraging the long standing "preferred supplier" arrangement for the provision of compressor related services;
- the expansion works have been constructed to both schedule and budget; and
- the pipeline cost is consistent with expectations.[106]

205. For the stay-in-business capital expenditure, Halcrow & Zincara assessed the prudence and efficiency of the expenditure by consideration of the justification for expenditures for seven expenditure items and categories of a value over $2 million in value, comprising 82 per cent of stay-in-business capital expenditure. These expenditure items comprised:

- $2.643 million (dollar values of 31 December 2010) for computer hardware at control room facilities;
- $4.667 million for motor vehicles;
- $4.044 million for SCADA equipment;

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105 Halcrow Pacific Pty Ltd and Zincara Pty Ltd, November 2010, Dampier to Bunbury Natural Gas Pipeline Access Arrangement Review – Technical Assessment.

106 Halcrow & Zincara, pp iv, 41 – 64.

- $3.570 million for replacement of close circuit vapour turbines that operate main line valves;
- $6.170 million for new works-management software;
- $27.125 million for compressor station replacement;
- $15.440 million for replacement of the microwave communications system.[107]

206. From this assessment, Halcrow & Zincara concluded that the stay-in-business capital expenditure for the 2005 to 2010 access arrangement period meets the prudence and efficiency requirement of rule 79 for reasons that:

- adequate justifications have been provided for the expenditure, with expenditure predominantly related to the replacement or improvement of aging infrastructure to maintain or improve safety and/or to maintain the integrity of the infrastructure and the services it is used to provide;
- appropriate use has been made of front end engineering design studies and consideration of options;
- DBP demonstrated use of effective tools for estimating costs that are consistent with accepted good industry practice;
- procurement decisions for major expenditure items of a recurrent nature were undertaken in accordance with procedures and guidelines for the items; and
- procurement was appropriately undertaken through processes of supplier relationships or tenders.[108]

207. The advice that stay-in-business capital expenditure for the 2005 to 2010 access arrangement period meets the prudence and efficiency requirements of rule 79 is provided despite an observation of Halcrow & Zincara that:

- a long term equipment strategy is yet to be fully developed and implemented; and
- DBP does not appear to maintain a detailed asset register that includes updated condition assessments.[109]

Project Management Fees and Project Management Retainer Fees

208. DBP has included amounts in capital expenditure for costs incurred as “project management fees” and “project management retainer fees” that were paid to contracted businesses that provided project management services for the expansion projects of the DBNGP.

209. The contracted businesses were Alinta Asset Management (from 2005 to 2009) and WestNet Energy Services (from 2009 to 2010). These entities are effectively the same business, with a change in ownership and business name having occurred in 2009.[110]

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107 Halcrow & Zincara, pp. 70 – 81.

108 Halcrow & Zincara, pp iv, 20, 21, 70 – 81.

109 Halcrow & Zincara, p. 20.

110 DBP Submission #1, pp. 14, 15.

210. These fees comprise two types of fees over and above direct costs incurred by the contracted businesses in connection with the expansion works:

- a "project management fee" of three per cent of all capital expenditure incurred in connection with capital works; and
- a "project management retainer fee" of $ 2 million per year over a three year period to incentivise the contracted businesses to provide the necessary personnel, corporate systems and procedures to maintain an ongoing capacity to provide the project management services irrespective of whether an additional capacity expansion is being planned or undertaken.[111]

211. The amounts of the project management fees and project management retainer fee are indicated by DBP to be as shown in Table 13.

Table 13 DBP's stated project management fees and project management retainer fees for the 2005 to 2010 access arrangement period ($ million, dollar values unspecified)[112]

Expansion project	Project management fee	Project management retainer fee
Expansion Stage 4	13.00	0
Expansion Stage 5A	18.15	0
Expansion Stage 5B	19.35	6.00
Total	**50.50**	**6.00**

212. DBP contends that the amounts of the project management fees and project management retainer fees are capital expenditure for reasons that:

- the project management fee was incurred in the process of expanding or replacing assets which form the DBNGP and which are used to provide services to users;
- the project management retainer fee was incurred to ensure that the Alinta Asset Management and WestNet Energy Services retained resources, processes and systems in place to be able to commence the management of an expansion project at short notice;
- the project management fee and project management retainer fee are explicit components of payments that DBP made to Alinta Asset Management and WestNet Energy Services under an "operating services agreement" with DBP;
- the standard shipper contract between DBP and users of the DBNGP considers, for tariff adjustment purposes, project management costs to form part of the capital cost of an expansion;
- an independent audit commissioned by DBP to verify the capital costs of the stage 4 and stage 5 expansion projects verified the project management fee as capital costs relating to the expansions.[113]

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111 DBP, 1 April 2010, Submission #9, section 17.

112 DBP, 1 April 2010, Submission #9, section 17.

113 DBP, 1 April 2010, Submission #9, section 17.

213. DBP further contends that the amounts of the project management fee and project management retainer fee are such as would be incurred by a prudent service provider acting efficiently, for the following reasons.[114]

- Alinta Asset Management and WestNet Energy Services were/are owned by one of the owners of the DBNGP – Alinta Limited and subsequently Prime Infrastructure. Alinta Limited was, and Prime Infrastructure is, the only member of the ownership consortium with experience in the ownership, operation and development of gas pipelines and, it is prudent for the ownership consortium of the DBNGP to rely on the resources and expertise of one of its members to provide services relating to the operation and expansion of the pipeline.
- The operating services agreement between the three owners of the DBNGP was negotiated on an arms-length basis. In the original negotiation, Alcoa and DUET were unrelated to Alinta Limited. Alcoa and DUET remain unrelated to Prime Infrastructure and Alcoa and DUET are sufficiently commercially motivated and experienced in contract negotiation to ensure that the project management fee and project management retainer fee are reasonable.
- The amount of the project management fee and project management retainer fee is efficient because it "covers" an expansive range of services in relation to capacity expansions and capital works, including design, front end engineering design (FEED studies), planning, construction, commissioning and final delivery of projects.
- DBP has an obligation under the SSC to minimise the capital costs of expansions and risks not being able to recover costs from shippers if it does not comply with this obligation.
- Under the operating service agreement, and for reasons of corporate reputation, Alinta Asset Management and WestNet Energy Services have been incentivised to incur costs efficiently, and hence the project management fee is reflective of costs incurred by a prudent service provider acting efficiently.

214. For the project management fee, DBP contends that this fee is an amount that would be incurred by a prudent service provider acting efficiently in accordance with good industry practice for reasons that:

- the project management fee is consistent with accepted practice for DUET in contracting for management of infrastructure assets, and it is also standard practice for DUET to contract with a party that has an ownership interest in the relevant asset to ensure an alignment of interests;
- project management fees are an accepted industry practice in the construction industry, and are consistent with economic theory and observed good industry practice; and
- the amount of the project management fee (at three per cent of direct costs) compares favourably with other fees payable in similar circumstances.[115]

[114] DBP, 1 April 2010, Submission #9, section 17.

[115] DBP, 1 April 2010, Submission #9, section 17.

215. The Authority accepts that the contractual arrangements between DBP and Alinta Asset Management and WestNet Energy Services, under which a range of activities were outsourced to a contracted party, may be a reasonable contracting strategy. Advice to the Authority is that alliance contracting arrangements such as the Operating Services Agreement are a reasonable contracting strategy for capital works given the time constraints in the enhancement projects and the limited number of suppliers available for this type of work.[116]

216. The matter of concern to the Authority is that the contractual arrangements involve a related party to one of the owners of the DBNGP that may give rise to incentives for costs to be in excess of efficient costs of undertaking the outsourced activities. These costs may therefore be inconsistent with the prudence and efficiency requirement of rule 79(1)(a). At issue is whether the owners of the DBNGP may have had the motivation and capability to use the outsourcing arrangement with a related party as a means of inflating apparent costs and having inflated costs reflected in regulated tariffs. The potential for this to occur has been previously identified by the Productivity Commission and other regulators. The Productivity Commission has stated:[117]

> Under [an outsourcing arrangement with a related party] the asset manager can engage in inappropriate transfer pricing, undermining the process of setting appropriate reference tariffs. Such transfer pricing occurs where a regulated service provider pays the associated asset manager an inflated price in order to raise its own cost structure, thus increasing the reference tariff for services provided by the regulated business. The affiliated asset manager makes inflated profits, which are ultimately passed through to the parent company.

217. In assessing whether the costs of the project management fee and the project management retainer fee are consistent with the prudence and efficiency requirement of rule 79(1)(a), other regulators have examined outsourcing arrangements between an owner of regulated infrastructure and a related party by reference to the following.[118]

- the circumstances under which the contractual arrangements were entered into and the nature of the contractual arrangements, and whether these are such as to enable the regulator reach a *prima facie* conclusion that the costs incurred under the arrangements are likely to be consistent with the prudence and efficiency requirement of rule 79(1)(a); and
- if the regulator is not able to reach a conclusion that the costs incurred under the contractual arrangements are consistent with the prudence and efficiency requirement of rule 79(1)(a), consideration of other evidence for the prudence and efficiency of these costs.

218. The circumstances under which the outsourcing contractual arrangements were entered into comprise the sale of the DBNGP from Epic Energy to the current owners in 2004. This involved the transfer of ownership of the DBNGP assets and business through the acquisition by a consortium of new owners of:

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116 Halcrow & Zincara, pp.48, 52.

117 Productivity Commission, 2004, Review of the Gas Access Regime, Report No. 31, pp. 458-9.

118 Essential Services Commission, Gas Access Arrangement Review 2008 – 2012 Final Decision – Public Version, pp. 46 – 60; Essential Services Commission of South Australia, June 2006, Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System, Final Decision, pp. 133 – 137.

- all of the units in the Epic Energy WA Pipeline Trust, now called DBNGP Pipeline Trust;
- all of the shares in Epic Energy (WA) Nominees Pty Limited, now called DBNGP (WA) Nominees Pty Ltd; and
- all of the shares in Epic Energy (WA) Transmission Pty Limited, now called DBNGP (WA) Transmission Pty Ltd.[119]

219. A separate entity established by the new owners (DBNGP Compressor Co Pty Ltd) separately purchased the compressor assets of the DBNGP.[120]

220. The new owners of the DBNGP were Diversified Utility and Energy Trusts (DUET), Alcoa of Australia Limited (through the wholly owned subsidiary Alcoa Energy Holdings Australia Pty Ltd) and Alinta Limited (through the wholly owned subsidiary Stageport Pty Ltd).[121]

221. At the time of the acquisition, the DBNGP (WA) Nominees Pty Ltd and DBNGP (WA) Transmission Pty Ltd entered into an "Operating Services Agreement" with Alinta Network Services, which was a wholly owned subsidiary of Alinta Limited.

222. DUET indicated at the time that the original Operating Services Agreement was entered into that the appointment of Alinta Network Services was consistent with part of its investment strategy, which was to appoint operators able to manage risks and improve operating efficiencies.[122] DUET further indicated that:[123]

> The appointment of Alinta Network Services as operator does not provide operator diversity for DUET but it does leverage Alinta's historical experience with DBNGP and the existing relationship between DUET and Alinta.

223. The original Operating Services Agreement required Alinta Network Services to provide all services necessary for the operation, maintenance and construction activities associated with the DBNGP and some support services associated with management and operations, such as finance, human resources, environmental and risk management services. The original Operating Services Agreement provided Alinta Network Services an exclusive right to provide the services for a period of 50 years.[124]

224. Fees payable to Alinta Network Services under the original Operating Services Agreement comprised:

- reimbursable costs – all costs and disbursements reasonably incurred or outlaid by Alinta Network Services in respect of its appointment under the Operating Services Agreement;

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119 DUET, November 2004, Product Disclosure Statement, p. 40.
120 DUET, November 2004, Product Disclosure Statement, p. 40.
121 DUET, November 2004, Product Disclosure Statement, pp. 40, 41.
122 DUET, November 2004, Product Disclosure Statement, p. 12.
123 DUET, November 2004, Product Disclosure Statement, p. 48.
124 DUET, November 2004, Product Disclosure Statement, p. 150.

- management fee – $2 million per annum at the commencement of the Operating Services Agreement to be adjusted annually for increases in gas throughput in the DBNGP (by a factor of 0.4 × the percentage increase in throughput) and inflation;
- incentive fee – 50 per cent of the reduction in reimbursable costs from a benchmark of the previous year's costs with adjustments for inflation, specified "change events" and changes to the asset management plan; and
- project management fee – 3 per cent of the cost of any additional capacity expansion and capital works.[125]

225. The Authority has considered whether the original Operating Services Agreement with Alinta Network Services is an "arm's-length" arrangement, that is, whether the DBNGP owners were motivated to minimise the cost of services provided under the Operating Services Agreement.

226. It is possible that Alinta Limited could have entered into arrangements with the other owners of the DBNGP with the effect of reducing or negating any commercial motivation to minimise the cost of services provided by Alinta Network Services. Alinta Limited could conceivably benefit from the price of services being paid under the Operating Services Agreement being set at a level greater than the costs of service provision. While Alinta Limited was only a minority owner of the DBNGP, such an arrangement may be acceptable to other owners of the DBNGP if the higher price for the contracted services is reflected in regulated tariffs and there is a means of distributing this benefit between the owners. For example, this could occur by Alinta Limited paying a higher amount for its share in the ownership of the DBNGP or there being a mechanism for "side payments" from Alinta Limited to reflect the benefits gained by higher contract costs being passed through in higher regulated prices.

227. The Authority has not, however, discovered any evidence of such arrangements. Taking into account that Alinta Limited was a minority owner of the DBNGP, the Authority is of the view that there is no reason to suspect that the original Operating Services Agreement is anything other than an arm's-length arrangement consistent with an intention of the DBNGP owners to minimise the cost of services provided under the agreement.

228. The Authority has also considered the terms of the original Operating Services Agreement and whether these terms would have provided Alinta Network Services with incentives to minimise costs. The Authority considers that the original Operating Services Agreement provided such incentives by:

- the structure of an incentive fee payable to Alinta Network Services which rewarded Alinta for achieving costs less than benchmarks, at least for operating costs;
- having key performance indicators for Alinta Network Services for each year and requiring reporting of performance against these key performance indicators; and

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125 DUET, November 2004, Product Disclosure Statement, p. 151; DBP, 1 April 2010, Submission #9 Attachment 7 (2004 Operating Services Agreement).

- requirements for Alinta Network Services to report on incurred costs, providing for transparency of costs to the owners of the DBNGP.[126]

229. The Authority observes that there was no explicit incentive arrangement in the fee provisions of the original Operating Services Agreement for minimising costs of capital expenditures. The Authority is nevertheless satisfied that the original Operating Services Agreement provided some incentive for minimising costs of capital expenditures by the requirements for reporting of performance against key performance indicators and by the requirement for transparent reporting of costs to the owners of the DBNGP.

230. In 2007, there was a change in ownership of the Alinta group of companies with the result that both the ownership interest in the DBNGP and the ownership of the contracted services company were transferred to Prime. There remains commonality of ownership of the contracted services company and a 20 per cent interest in the DBNGP.[127]

231. In 2009, the Operating Services Agreement was renegotiated to derive the Amended and Restated Operation Services Agreement. The Amended and Restated Operation Services Agreement is a contract between DBNGP (WA) Nominees Pty Ltd, DBNGP (WA) Transmission Pty Ltd and Alinta Asset Management Pty Ltd. The rights and obligations of Alinta Asset Management Pty Ltd have subsequently been novated to WestNet Energy Services Pty Ltd.

232. The effect of renegotiation of the agreement was that:

    - the DBP group of companies assumed responsibility for functions relating to the operation, maintenance, minor capital works and expansion of the DBNGP; and
    - there is continued outsourcing of office and building management services, expansion-related project management services and IT services.[128]

233. Fees payable under the Amended and Restated Operating Services Agreement were renegotiated to terminate the management fee, but to add a project management retainer fee calculated as an inflation-escalated value of $2 million in dollar values of 31 December 2004. In regard to this fee, the Authority observes that:

    - the value to the outsourced service provider of the project management retainer fee approximately offsets the value of the terminated management fee;
    - the project management retainer fee would be payable from the date of the Amended and Restated Operating Services Agreement and, hence, payable for the years 2009 and 2010, which is inconsistent with DBP having proposed an amount of $6 million of capital expenditure in respect of this fee for the 2005 to 2010 access arrangement period; and

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[126] DBP, 1 April 2010, Submission #9 Attachment 7 (Operating Services Agreement).

[127] DBP, 1 April 2010, Submission #1, section 6.1.

[128] DBP, 1 April 2010, Submission #1, section 6.2; DBP, 1 April 2010, Submission #1 Attachment 5 (Amended and Restated Operating Services Agreement). The Amended and Restated Operating and Services Agreement is dated 9 February 2009

- the obligations of WestNet Energy Services Pty Ltd in respect of the project management retainer fee are described in the Amended and Restated Operating Services Agreement only in very general terms of ensuring provision of "the necessary personnel, corporate systems and procedures to maintain an ongoing capacity to provide the project management services irrespective of whether an additional capacity expansion is being planned or undertaken".[129]

234. There is nothing in the new terms of the Amended and Restated Operating Services Agreement or the circumstances of the negotiation to cause the Authority to suspect that the agreement is anything other than an arm's-length arrangement consistent with an intention of the DBNGP owners seeking to minimise the cost of services provided under the agreement.

235. However, the Authority is not satisfied that the project management retainer fee is consistent with the prudence and efficiency requirements of rule 79(1)(a). DBP has not provided information that satisfies the Authority that the payment of the project management retainer fee is necessary to be able to contract for project management services within the required time frames for an expansion of the DBNGP.

236. Moreover, the Authority is not satisfied that the project management retainer fee is a genuine fee for a service or facility to be provided by WestNet Energy Services Pty Ltd, given:

- the lack of a detailed specification in the Amended and Restated Operating Services Agreement of any relevant requirements to be met by WestNet Energy Services Pty Ltd in return for the fee;
- a view of expert engineering advisors to the Authority that there is a lack of precedent to suggest that the nature and quantum of the project management retainer fee are consistent with common industry practice; and
- DBP has forecast no expansion of the DBNGP for the 2010 to 2015 access arrangement period.

237. In the circumstances, the Authority is also concerned that the project management fee may represent a negotiated compensation to Alinta Asset Management and WestNet Energy Services Pty Ltd for the termination of the management fee, rather than a fee for an additional service or obligation under the Amended and Restated Operating Service Agreement.

Conclusion on the Prudence and Efficiency of Capital Expenditure in the 2005 to 2010 Access Arrangement Period

238. Having addressed the above matters, the Authority is not satisfied that all of the capital expenditure in the 2005 to 2010 access arrangement period satisfies the prudence and efficiency requirements of rule 79(1)(a).

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129 DBP,1 April 2010, Submission #1 Attachment 5 (Amended and Restated Operating Services Agreement, clause 7.5)

239. The Authority observes that there are inconsistencies in the values of capital expenditure indicated by DBP in different documents and in audited values of capital expenditure for expansion stages 4 and 5A. The Authority will only accept audited values of capital expenditure for addition to the capital base. The Authority will require adjustment of the values of capital expenditure for stage 4 that are to be added to the capital base to reflect the audited values. The Authority will also require independent audit reports for stage 5B before the value to be added to the capital base in respect of this expansion stage is finally approved.

240. The Authority is of the view that the amount of the project management retainer fee does not satisfy the prudence and efficiency requirements of rule 79(1)(a) and requires that the amount of this fee be removed from the capital expenditure. DBP has not provided a clear statement of the value of the project management retainer fee in specified nominal or real values. The Authority has therefore estimated the amount of this fee for the three year period 2008 to 2010 as an inflation indexed amount of $2 million in 2004. The amounts deducted (in dollar values of 2010) comprise $2.375 million in each of the three years.[130]

Justification of Capital Expenditure under Criteria of Rule 79(2)

241. DBP contends that the capital expenditure for expansion of the DBNGP meets the justification criteria of rule 79(2) on the grounds that:

- the expansion investment was undertaken to comply with undertakings to the Australian Competition and Consumer Commission under section 87B of the *Trade Practices Act 1974* to expand the capacity of the DBNGP, which constitutes a regulatory obligation or requirement within the meaning of rule 79(2)(c)(iii);[131] and/or
- the entire amount of capital expenditure on the stage 4, 5A and 5B expansion programs meets the requirement of rule 79(2)(a) of the NGR that the overall economic value of the expenditure is positive.[132]

242. DBP does not specifically contend that the stay-in-business capital expenditure meets the criteria of rule 79(2) but DBP's submission on this category of capital expenditure sets out justifications for this expenditure in terms of compliance with DBP's safety case for the pipeline and maintaining the capacity of the DBNGP to meet demand for services.[133]

243. Each of these grounds of justification of capital expenditure under the criteria of rule 79(2) is examined below.

Compliance with a Regulatory Obligation or Requirement

244. DBP claims that the expansion investment was undertaken to comply with undertakings to the Australian Competition and Consumer Commission that comprise a regulatory obligation within the meaning of rule (79(2)(c)(iii).

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130 Although the Amended and Restated Operating Services Agreement commenced in 2009, DBP's statement of costs includes an amount of the project management retainer fee for each of the three years 2008 to 2010.

131 DBP, 1 April 2010, Submission #9, section 2 and paragraph 18.4.

132 DBP, 1 April 2010, Submission #9, paragraph 18.5.

133 DBP, 1 April 2010, Submission #10.

245. DBP refers to a part of the definition of 'regulatory obligation or requirement" under section 6(1)(b)(v) of the Law that indicates a regulatory obligation or requirement to include:[134]

> an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act (other than national gas legislation or an Act of a participating jurisdiction or an Act or instrument referred to in subparagraphs (ii) to (iv)), that materially affects the provision, by a service provider, of pipeline services to which an applicable access arrangement applies.

246. DBP submits that the capital expenditure incurred to expand the capacity of the DBNGP falls within this definition of a regulatory obligation or requirement by reason that the expenditure is necessary to comply with the undertakings to the ACCC which comprise a regulatory obligation or requirement.[135]

247. The relevant requirements under the undertakings to the ACCC are contained in provisions 5.6 and 5.6 of the undertaking document,[136] below.

5.6 Capacity Expansion Rights for Prospective Shippers

(a) Subject to clause 5.6(b), DBNGP Holdings undertakes to ensure that EEWAT offers to all prospective Shippers who require a T1 Service, a Standard Shipper Contract that contains Capacity Expansion Rights that are not materially less favourable than the Capacity Expansion Rights contained in any other Shipper Contract for a T1 Service.

(b) To avoid doubt, nothing in clause 5.6(a):

(i) requires DBNGP Holdings or EEWAT to enter into a Shipper Contract with a Prospective Shipper if it would not be required to do so under the Gas Access Law and the Access Arrangement;

(ii) prevents DBNGP Holdings or EEWAT from requiring a Prospective Shipper to enter into a Standard Shipper Contract for a T1 Service, which contains particular Capacity Expansion Rights, on terms and conditions that are equivalent to other Standard Shipper Contracts that contain equivalent Capacity Expansion Rights; nor

(iii) requires DBNGP Holdings or EEWAT to offer to any Shipper Capacity Expansion Rights that are the same as the Capacity Expansion Rights in the Exempt Alcoa Contract.

5.7 Obligation to Expand Capacity

(a) Obligation to Expand

Subject to this clause 5.7, DBNGP Holdings undertakes to expand the Capacity of the DBNGP between the DOMGAS Dampier Plant Inlet Point and CS10 by not less than 100 TJ/d, in aggregate, to meet the known Capacity

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[134] DBP, 1 April 2010, Submission #9, paragraph 3.26.

[135] DBP, 1 April 2010, Submission #9, paragraph 3.27.

[136] Trade Practices Act 1974 Undertaking to the Australian Competition and Consumer Commission under Section 87B by Alinta Limited, Alinta Network Services Pty Ltd, Alcoa of Australia Limited, AMPCI Macquarie Infrastructure Management No 2 Limited in its capacity as the responsible entity of the Diversified Utility and Energy Trust No 2, DBNGP Holdings Pty limited, 22 October 2004.

requirements of Contracted Shippers or Prospective Shippers who enter into Standard Shipper Contract.

(b) Timeframe

DBNGP Holdings undertakes to complete the expansion of Capacity under clause 5.7(a) no later than 5 years following completion of the Proposed Acquisition.

(c) Obligation to Invest in the Capacity Expansion

DBNGP Holdings undertakes to invest up to $400 million in connection with the expansion of Capacity under clause 5.7(a) provided that Shippers that require the Capacity have entered into Standard Shipper Contracts as contemplated by clause 5.7(a).

(d) Feasibility, Safety and Reliability

DBNGP Holdings is not required to carry out the expansion of Capacity under clause 5.7(a) if it reasonably determines that the expansion is not:

(i) technically or economically feasible; or

(ii) consistent with the safe and reliable provision of DBNGP Services.

248. DBP further submits that all, or at least part, of the expenditure made by DBP in connection with the expansion of capacity of the DBNGP since 2005 meets the test under rule 79(2)(c)(iii) in that it was necessary to comply with obligations under clauses 5.6 and 5.7 of the undertaking to the ACCC. The relevant part of DBP's submission is reproduced as follows.[137]

3.36 … DBP submits that:

(a) all the expenditure made by DBP in connection with the expansion of the capacity of the DBNGP since 2005 meets the test under Rule 79(2)(c)(iii) of the NGR in that it is necessary to comply with the regulatory obligation of clause 5.6(a) of the 2004 Undertakings, given that all the expansions since 2005 have been undertaken as a result of the operation of clause 16 of the SSCs (except in relation to the capacity provided for Alcoa under the Exempt Contract);

(b) If the ERA does not agree with the above submission or in the alternative, the initial $400m expended by DBP meets the test under Rule 79(2)(c)(iii) of the NGR in that it is necessary to comply with the regulatory obligation or requirement of clause 5.7 of the 2004 Undertakings to expand the capacity of the DBNGP between DOMGAS Dampier Plant Inlet Point and CS10 by not less than 100 TJ/day, in aggregate, to meet the known Capacity requirements of Contracted Shippers or Prospective Shippers who enter Standard Shipper Contracts that comply with clause 5.6 under and in accordance with the terms of that contract (the "**Expansion**"); and

(c) In the alternative, the capacity provided and expenditure made by the DBP group (including DBP) in meeting the capacity requirements of shippers and prospective shippers under Standard Shipper Contracts that were the subject

137 DBP, 1 April 2010, Submission #9, paragraph 3.36.

of access requests that were in existence as at 27 October 2004 meets the test under Rule 79(2)(c)(iii) of the NGR in that it is necessary to comply with the regulatory obligation or requirement of clause 5.7 of the 2004 Undertakings.

249. One party that made a submission to the Authority on the proposed revised access arrangement contests DBP's submission that the undertakings to the ACCC comprise a regulatory obligation or requirement that is within the scope of rule 79(2)(c)(iii) of the NGR.[138]

250. The Authority concurs with this submission and takes the view that clauses 5.6 and 5.7 of the undertakings to the ACCC do not constitute a regulatory obligation that compelled DBP to expand the DBNGP and do not justify capital expenditure under rule 79(2)(c)(iii). Under clause 5.7 of the undertakings, DBP would only be required to expand the capacity of the DBNGP to meet known capacity requirements of users that enter into a standard shipper contract. Clause 5.6 of the undertakings makes it clear that DBP would not be required to enter into a standard shipper contract if DBP would not be required to do so under the (then) Gas Access Law and the Access Arrangement. Accordingly, the Authority is of the view that clauses 5.6 and 5.7 of the undertakings to the ACCC do not add to any possible expansion obligations that already existed at the time of the undertakings under the Gas Access Law, in particular under section 6.22 of the Gas Code. These expansion obligations would compel DBP to expand the DBNGP only in limited circumstances; that is, where the expansion is economically feasible and the service provider is not required to fund part or all of the expansion.

Incremental Revenue

251. DBP submits that the expenditure associated with each of stages 4, 5A and 5B of expansion of the DBNGP, when considered as separate investments, meets the requirement of rule 79(2)(b) of the NGR. That is, that the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure.[139]

252. In support of this contention, DBP has submitted a report by a consultant.[140]

253. The assessment of the net present value of capital expenditure was undertaken on the basis of:

- determining an amount of incremental revenue from all capital expenditure for the three stages of pipeline expansion, including forecast expenditure in 2011 for completion of stage 5B;
- an extrapolation of DBP's T1 Service reference tariff for the 2010 year over a period to 2039 with no new capital expenditure (after stage 5B), and with this extrapolation showing a four per cent annual reduction in tariffs (in real terms) after 2010 (reflecting a progressive decline in the capital base with no new capital expenditure);

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138 Alinta Pty Limited, 9 July 2010, p. 3.

139 DBP Submission #9, paragraphs 18.9, 18.10.

140 DBP Submission #9, Attachment 25.

- a discount rate equal to the rate of return of 7.24 per cent (real, pre-tax), which is the rate of return applied in determining reference tariffs in the 2005 to 2010 access arrangement period; and
- additional demand for services (contracted capacity and load factor) for each stage of expansion, as projected by DBP.

254. The analysis determined the net present value of the expansion capital expenditure to be negative for each stage of expansion and in total, as shown in Table 14. According to these calculations, an amount of $1,123.12 million would be justified under rule 79(2)(b), which is less than the total capital cost of the expansions.

Table 14 DBP submitted net present values of stages 4, 5A and 5B of the DBNGP expansion as calculated by Marsden Jacob & Associates (real $million, dollar values of December 2009)[141]

Project	Capital cost	Net present value of net incremental revenue less the present value of capital costs
Expansion Stage 4	474.26	-350.44
Expansion Stage 5A	638.51	-264.51
Expansion Stage 5B	672.28	-48.19
Total	**1,785.05**	**-661.93**

255. The conclusions of the consultant's analysis were as follows.

- For each of the three stages of expansion, the present value of the expected net incremental revenue is less than the present value of the capital expenditure. For each stage, the new capital expenditure is not justifiable with reference to the criteria in rule 79(2)(a). The total new capital expenditure for each of the three stages of expansion is, therefore, not conforming.
- After 35 years (in 2039), the amount by which the present value of the expected net incremental revenue falls short of the present value of the capital expenditure for the combined project is approximately $662 million (real, December 2009).

256. These conclusions are contrary to DBP's submission that all of the capital expenditure on expansion is justified by incremental revenue (see paragraph 251, above). The determination of the value of incremental revenue indicates that only about two thirds of the expansion capital expenditure would satisfy the incremental revenue test in rule 79(2)(a).

141 DBP, 1 April 2010, Submission #9, Attachment 25 p. 11.

Economic Value of Expenditure

257. DBP submits that the entire amount of capital expenditure for all of stages 4, 5A and 5B of expansion of the DBNGP is justified under rule 79(2)(a), in that the overall economic value is positive.[142] In support of this submission, DBP refers to analysis undertaken by its consultant.[143]

258. The consultant undertook analysis to show a net economic benefit from the expansion of the DBNGP arising from:

- incremental revenues to the owners of the DBP;
- additional use of gas in place of electricity by retail gas customers supplied by the principal gas retailer (Alinta); and
- additional use of gas in place of either coal or diesel in electricity generation.[144]

259. The benefit of incremental revenue to the pipeline owners was estimated at a present value (net of incremental operating expenditure) of $592.69 million over 20 years to 2024.[145]

260. The benefit from use of gas rather than electricity by retail customers of Synergy was estimated at $96 million per annum (in 2009 dollar values)[146] on the basis of assumptions of:

- a usage equivalence of one retail billing unit of gas (approximately 3.6 MJ) with one billing unit of electricity (one kilowatt hour), that is, a household can substitute one billing unit of gas for one billing unit of electricity;
- a unit price of gas of 8.81 cents per unit projected to come into force on 1 April 2010;
- a unit price of electricity of 18.94 cents per kilowatt hour projected to come into force on 1 July 2010; and
- a total substitution of gas for electricity based on the additional amount of capacity contracted by Synergy from the three expansion stages of 11 TJ per day, equivalent to 948.6 million retail gas units per year.[147]

261. The benefit from use of gas rather than a mix of coal and diesel for electricity generation was estimated at $139.81 million per annum (in 2009 dollar values)[148] on the basis of assumptions of:

- a substitution of gas for equal proportions of coal and diesel (in units of primary-fuel energy);

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142 DBP, 1 April 2010, Submission #9, section 18.

143 DBP, 1 April 2010, Submission #9, Attachment 25.

144 DBP, 1 April 2010, Submission #9, Attachment 25, pp. 13 – 23.

145 DBP, 1 April 2010, Submission #9, Attachment 25, p. 22.

146 DBP, 1 April 2010, Submission #9, Attachment 25, p. 16.

147 Additional DBNGP capacity of 11 J/day with 85% load factor and converted to an annual number of units of 3.6 MJ.

148 DBP, 1 April 2010, Submission #9, Attachment 25, p. 21.

- cost differences arising only from differences in primary fuel cost and not other costs of generation plants;
- unit prices for alternative fuels of $9.48 per GJ for gas, $2.44 per GJ for coal and $21.97 per GJ for diesel (in dollar values of 2009); and
- a substitution of gas for coal/diesel based on the additional amount of DBNGP capacity contracted by electricity generators from the three expansion stages of 192.32 TJ per day.

262. In total, the consultant estimated a net economic benefit in present value terms of $965 million over the period to 2024, taking into account a present value cost of investment of $1,308.22 million, a present value of revenue to the pipeline owner of $592 million, and a present value of additional gas use of $1,680 million (with present values calculated at a real discount rate of 7.24 per cent).

263. The analysis also indicated that there would be economic benefits in the additional use of gas other than by retail customers and electricity generators (which together account for 57 per cent of the increase in gas throughput in the DBNGP), but did not quantify these benefits.

264. The Authority accepts that benefits of the general type identified by may occur as a result of the expansions, but considers that the analysis is too simplistic and inexact to be relied on as an indication of the values of these economic benefits. The Authority considers that shortcomings of the analysis of economic benefits include the following.

- The analysis considers only very simplistic scenarios of direct physical substitution of gas for other energy sources for both retail gas customers and electricity generators. The Authority considers that this fails to adequately address the effects of a greater gas supply to the south west of Western Australia (enabled by expansions in capacity of the DBNGP) on relative prices of energy sources, investments in energy infrastructure, competition in energy markets and costs of energy supplies to end users.
- The analysis of substitution between gas and electricity by retail gas customers was undertaken applying unjustified assumptions on the substitutability of electricity and gas and derives unreliable estimates of the benefits to retail energy customers of a greater gas supply.
- The analysis of substitution between gas and other fuel types in electricity generation involves too simplistic an assessment of the cost effects of substitution of generation types in the electricity market (gas, coal and diesel-fired) by failing to take into account both capital and operating costs of generation with different fuel types and the investment decisions in generation plant that would be affected by the additional DBNGP capacity.

265. The Authority therefore considers that DBP has not presented a reliable quantification of economic benefits from the expansions in capacity of the DBNGP.

266. Notwithstanding the deficiencies of DBP's submission on the economic benefits of expansion of the DBNGP, the Authority is of the view that inferences on economic benefits can be drawn from the contractual arrangements under which the expansions to capacity have occurred.

267. DBP has expanded the DBNGP only to the extent that users receiving gas transmissions services under the terms of the SSC have entered into contracts for the additional capacity. DBP has not expanded capacity beyond levels contracted for under the SSC.

268. Relevant terms of the SSC are that the user must enter into a contractual commitment for services for a minimum of 15 years and pay a tariff for the contracted capacity that is the tariff under the SSC. Subsequent to 2016, the reference tariff will be that as determined under the access arrangement, which may reasonably be expected to reflect the cost of pipeline expansions. A user contracting for additional capacity may also be required to make a contribution to the capital cost of the pipeline expansion.[149]

269. Under the terms of the SSC, the expansions in capacity of the DBNGP have occurred with users of the DBNGP knowingly and willingly being exposed over a long contractual term to transmission tariffs that reflect the expansion costs. That is, all of the current users of the DBNGP have willingly signed up to the SSC in full knowledge of eventual exposure to the cost of pipeline expansions. As users of the DBNGP may be assumed to be behaving in a commercially reasonable and rational manner, these contractual arrangements are *prima facie* evidence that expansions to capacity of the DBNGP have only occurred where the benefits to users of the transmission services exceed the costs of the expansion as reflected, or eventually to be reflected, in transmission tariffs.

270. It is possible that the scope and cost of expansions to the DBNGP may have been greater than contemplated by users at the time of entering into the SSC with DBP, with the result that some users may be exposed to costs of pipeline expansion (at the time that they become subject to a reference tariff) even though these particular users did not increase their demand for gas transmission. This could weaken the evidence that there is a positive overall economic value to expenditure on expansion of the DBNGP. However, notwithstanding this qualification, the contractual commitments made by users to expansion of the DBNGP and meeting the costs of this expansion provide sufficient evidence to conclude that the overall economic value of the expenditure on expansion of the DBNGP is positive.

Safety and Reliability

271. DBP has provided justification for expenditure items of stay-in-business capital expenditure in terms of needs to maintain the capacity and reliability of the DBNGP for service provision and to maintain health and safety standards.[150]

272. As already indicated above in relation to the prudence and efficiency of capital expenditure, the Authority has received expert advice from Halcrow & Zincara that the stay-in-business capital expenditure is adequately justified against criteria and requirements of safety and reliability (paragraph 205 and following, above). On this basis, the Authority accepts that the stay-in-business capital expenditure for the 2005 to 2010 access arrangement period conforms with safety and reliability criteria in rule 79(2)(c)(i) and (ii).

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[149] DBP, Standard Shipper Contract – Full Haul T1, clauses 16, 20.

[150] DBP Submission #10, pp. 20 – 57.

Conclusion on the Justification of Capital Expenditure under rule 79 of the NGR

273. Having considered the above matters, the Authority is of the view that not all of the capital expenditure in the 2005 to 2010 access arrangement period satisfies the prudence and efficiency requirements of rule 79(1)(a).

274. The Authority has identified inconsistencies in the values of capital expenditure indicated by DBP in different documents and in audited values of capital expenditure for expansion stages 4 and 5A. The Authority will only allow audited values of capital expenditure to be added to the capital base. The Authority requires adjustment of the values of capital expenditure for stages 4 and 5A that are to be added to the capital base to reflect the audited values. The Authority will also require independent audit reports for the expansion capital expenditure of the stage 5B expansion and for stay-in business capital expenditure before the values to be added to the capital base are finally approved.

275. For stay-in-business capital expenditure, the Authority is the view that the amount of the project management retainer fee does not satisfy the prudence and efficiency requirements of rule 79(1)(a). The Authority requires that the amount of this fee ($2.373 million in each of the years 2008, 2009 and 2010; dollar values of 31 December 2010) be removed from the amount of capital expenditure to be added to the capital base.

276. These required amendments to the values of conforming capital expenditure comprise a reduction in conforming capital expenditure of $76.684 million (dollar values of 31 December 2010) from that proposed by DBP, corresponding to a reduction of 4.1 per cent.

277. Taking account, also, of the Authority's requirement for reclassification of $4.45 million expenditure on linepack gas in 2009 from other depreciable assets to other non-depreciable assets, the Authority's required amended values of conforming capital expenditure to be added to the capital base for the 2005 to 2010 access arrangement period are shown in Table 15.

Table 15 Authority's required amended values of conforming capital expenditure for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)

Year	2005	2006	2007	2008	2009	2010
Forecast Expenditure						
Pipeline	0.749	3.041	241.866	514.734	0.153	445.642
Compression	-	51.062	161.072	121.361	4.417	170.144
Metering	-	0.057	-	-	0.068	0.050
Other depreciable	0.044	3.553	2.336	5.810	2.260	66.820
Other non-depreciable	-	-	-	-	4.568	-
Total	**0.793**	**57.713**	**405.274**	**641.905**	**11.466**	**682.657**

Required Amendment 5

The value of conforming capital expenditure for the 2005 to 2010 access arrangement period must be amended to values as indicated in Table 15 of this draft decision.

Forecast Capital Expenditure for the 2011 to 2015 Access Arrangement Period

Forecast Additions of Conforming Capital Expenditure to the Capital Base

278. DBP's forecast of conforming capital expenditure for the 2011 to 2015 access arrangement period comprises:

- an amount of $49.144 million (dollar values of 31 December 2010) for expansion of the DBNGP, being a final amount in respect of expansion stage 5B that is expected to be capitalised in financial accounts in 2011; and
- an amount of $87.364 million (dollar values of 31 December 2010) for stay-in-business capital expenditure.

279. The annual amounts of capital expenditure and asset categories of expenditure are shown in Table 16.

Table 16 DBP's forecast conforming capital expenditure for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[151]

Year ending 31 December	2011	2012	2013	2014	2015	Total
Expansion						
Pipelines	5.188	-	-	-	-	**5.188**
Compression	8.161	-	-	-	-	**8.161**
Metering	0.145	-	-	-	-	**0.145**
Other depreciable assets	35.651	-	-	-	-	**35.651**
Non-depreciable assets	-	-	-	-	-	**-**
Sub-total	**49.144**	**-**	**-**	**-**	**-**	**49.144**
Stay in business						
Pipelines	5.571	4.463	4.827	0.631	0.836	**16.328**
Compression	10.615	8.610	3.981	4.740	8.012	**35.958**
Metering	0.328	0.498	2.724	2.724	0.159	**6.433**
Other depreciable assets	6.271	4.868	4.263	6.930	6.315	**28.647**
Non-depreciable assets	-	-	-	-	-	**-**
Sub-total	**22.785**	**18.439**	**15.794**	**15.024**	**15.322**	**87.364**
Total						
Pipelines	10.759	4.463	4.827	0.631	0.836	**21.516**
Compression	18.775	8.610	3.981	4.740	8.012	**44.118**
Metering	0.473	0.498	2.724	2.724	0.159	**6.577**
Other depreciable assets	41.922	4.868	4.263	6.930	6.315	**64.297**
Non-depreciable assets	-	-	-	-	-	**-**
Total	**71.929**	**18.439**	**15.794**	**15.024**	**15.322**	**136.508**

280. The Authority has addressed the forecast of capital expenditure as follows, addressing separately the forecast of expansion capital expenditure proposed by DBP and the forecast of stay-in-business capital expenditure.

Forecast Expansion Capital Expenditure Proposed by DBP

281. For expansion capital expenditure, information provided by DBP indicates only that the forecast expenditure of $49.144 million (dollar values of 31 December 2010) is a final amount in respect of expansion stage 5B that is expected to be capitalised in financial accounts in 2011.

151 DBP Submission #11, sections 4, 5.

282. In relation to actual capital expenditure in the 2005 to 2010 access arrangement period the Authority has concluded that the capital expenditure incurred for the stage 5B expansion conforms to the criteria of rule 79. Accordingly, the Authority considers that forecast capital expenditure for stage 5B in 2011 also conforms to the criteria of rule 79. The Authority notes that prior to determining the value of the capital base at the commencement of the next access arrangement period in 2016, only a value of the actual expenditure that has been verified by audit of costs will be added to the capital base.

Forecast Stay-in-Business Capital Expenditure

283. For stay-in-business capital expenditure, DBP has not provided information to the Authority indicating the methods used to derive the forecast of stay-in-business capital expenditure. However, the breakdown of the forecast expenditure presented in a submission from DBP suggests that the forecast was derived from a plan of capital works projects and expenditure items and estimates of costs for these planned projects.[152] The same breakdown of forecast stay-in-business expenditure provides a description of each project or expenditure item and a justification for DBP's position that the forecast expenditure conforms to the criteria of rule 79.

284. In considering the forecast of stay-in-business capital expenditure, the Authority has assessed whether the forecast expenditure conforms to the prudence and efficiency requirement of rule 72(1)(a). The Authority accepts that the forecast stay-in-business capital expenditure is for the purposes of maintaining and improving the safety of services and maintaining the integrity of services and is justifiable under the criteria of rule 79(2).

285. To assess the prudence and efficiency of forecast stay-in-business capital expenditure, the Authority has considered the changes over time in levels of expenditure and the justification provided by DBP for the proposed capital projects and expenditure items.

286. The time series of actual and forecast stay-in-business capital expenditure is shown in Figure 3. For the purposes of comparison of the actual and forecast values, the values of stay-in-business capital expenditure include values of the project management retainer fee payable to WestNet Energy Services Pty Ltd under the terms of the Operating Services Agreement.

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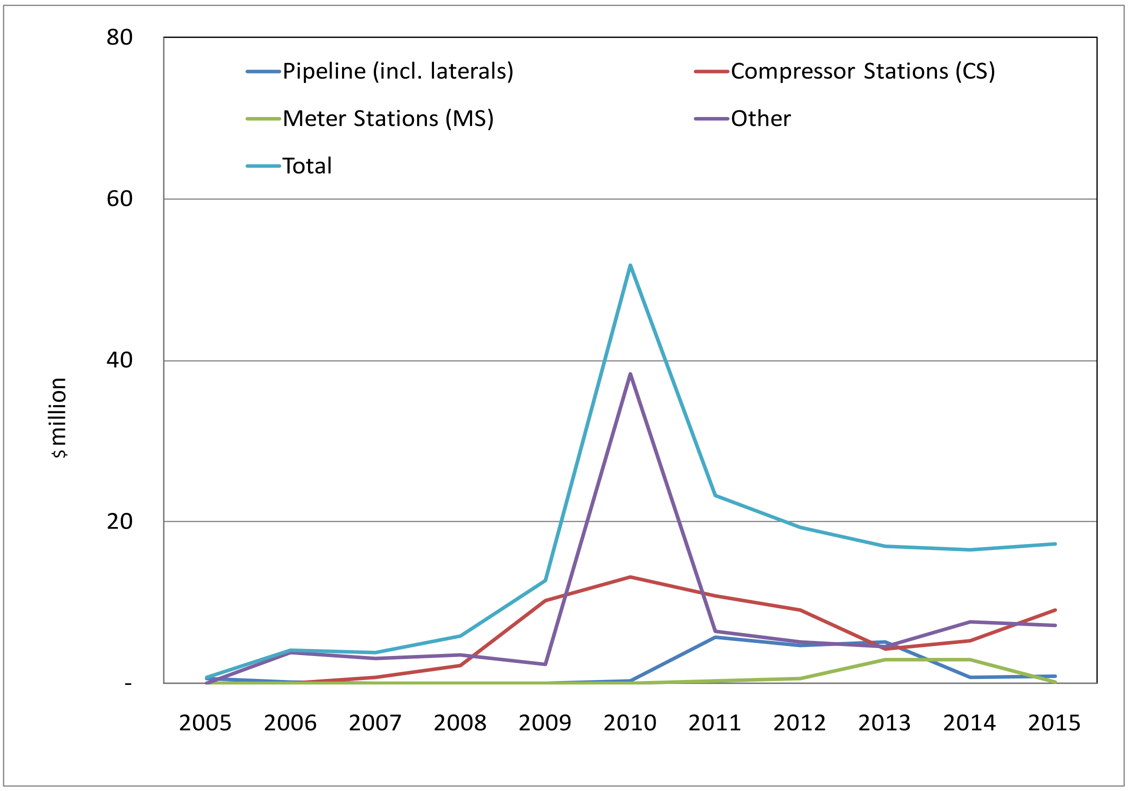
[152] DBP Submission # 11.

Figure 3: Actual (2005 to 2009) and forecast (2010 to 2015) stay-in-business capital expenditure (including costs of the project management retainer fee) (dollar values of 31 December 2010)[153]



287. The time series of stay-in-business capital expenditure comprises:

- a low value of approximately $0.8 million (dollar values of 31 December 2010) in 2005;
- values of between approximately $4 million and $6 million in 2006 to 2008;
- large increases in expenditure to approximately $13 million in 2009 and $52 million in 2010;
- a forecast declining trend in expenditure over the 2011 to 2015 access arrangement period, from approximately $22 million in 2011 to $13.5 million in each of 2014 and 2015.

288. DBP has not provided any direct explanation for the large peak in stay-in-business capital expenditure in 2010 and the subsequent forecast decline in expenditure over the course of the 2011 to 2015 access arrangement period.

153 DBP Submission 10 and 11.

289. Turning to a consideration of the proposed capital projects and expenditures that make up the forecast of stay-in-business capital expenditure, the Authority has received advice from Halcrow & Zincara who reviewed the proposed capital projects and expenditure items and drew conclusions on whether these conform to the prudence and efficiency requirement of rule 79(1)(a), taking into account information provided by DBP. Halcrow & Zincara provided an opinion that either the amounts or timing of costs for several capital projects or expenditure items do not conform to the prudence and efficiency requirement, as follows:

- LM500 Compressor Units Decommissioning – DBP has forecast a cost of $[redacted] million (dollar values of 31 December 2010) to examine decommissioning of compressor units. Halcrow & Zincara are of the view that the study and expenditure is justified, but note that no allowance is made in the forecast stay-in-business capital expenditure for implementing the decommissioning. Taking the view that this indicates that no actual decommissioning works are intended during the 2011 to 2015 access arrangement period, Halcrow & Zincara recommend that the FEED study and expenditure could be shifted to 2014.[154]

- Replacement of PVC oil waste pipes at compressors – DBP has forecast a cost of $[redacted] million (dollar values of 31 December 2010) in 2011 for replacement of oil waste pipes at compressors. Depending upon how many compressors are to have pipes replaced, this corresponds to a cost per compressor of between $[redacted] and $[redacted] (dollar values of 31 December 2010). Halcrow & Zincara consider this cost to be excessive and recommend a forecast cost of $21,000 per compressor, to a maximum total cost of $267,000.[155]

- Replacement of compressor exhaust (CS6 Nova Pignone Compressor) – DBP has forecast a cost of $[redacted] million (dollar values of 31 December 2010) in 2014 for replacement of a compressor exhaust system at CS6. Halcrow & Zincara indicate that DBP has established a case for these works (based on a risk of failure), but has not provided sufficient information to justify the delay of the works until 2014 given the assessed risk of failure nor to justify the cost estimate. On this basis, Halcrow & Zincara recommend that the cost be excluded from the forecast of stay-in-business capital expenditure.[156]

- Standardisation of turbine/compressor “control logic” – DBP has forecast a cost of $[redacted] million (dollar values of 31 December 2010) in 2012 for standardisation of a part of a part of compressor control equipment control equipment. Halcrow & Zincara found that DBP had not provided sufficient information to demonstrate that this standardisation could not be better undertaken as part of an upgrade of compressor control equipment projected as a separate item of stay-in-business capital works. On this basis, Halcrow & Zincara recommend that the cost be excluded from the forecast of say-in-business capital expenditure.[157]

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154 Halcrow & Zincara, pp. 83, 84.

155 Halcrow & Zincara, pp. 85, 86.

156 Halcrow & Zincara, pp. 90, 91.

157 Halcrow & Zincara, pp. 91, 92.

- Replacement of underground pipework at compressor stations – DBP has proposed a cost of $[redacted] (dollar values of 31 December 2010) in each year of the 2011 to 2015 access arrangement period for replacement of pipework at compressors. Halcrow & Zincara consider the replacement to be prudent, but consider the unit cost per compressor to be unjustifiably greater than the cost of similar works in the 2005 to 2010 access arrangement period. On this basis, Halcrow & Zincara recommend the forecast cost be reduced to $0.615 million per year (dollar values of 31 December 2010).[158]
- Replacement of water pipework at CS2 – DBP has proposed a cost of $[redacted] (dollar values of 31 December 2010) in 2011 for replacement of water pipework at CS2. Halcrow & Zincara consider that DBP has provided insufficient information to justify the cost and recommend that half of the proposed cost be excluded from the forecast.[159]
- Installation of gas chromatographs – DBP has proposed a cost of $[redacted] (dollar values of 31 December 2010) in 2011 for a FEED study for installation of additional gas chromatographs on the DBNGP for monitoring of gas quality. Halcrow & Zincara consider that this cost is excessive for the study and consider that a lower cost of $21,000 (dollar values of 31 December 2010) should be included in the forecast.[160]
- Relocation of microwave batteries – DBP has proposed a cost of $[redacted] (dollar values of 31 December 2010) in 2011 for a FEED study on relocation of microwave batteries. Halcrow and Zincara consider that there is an unwarranted period of time between the FEED study and the forecast timing of the works, and consider that the cost should be deferred until 2014.[161]
- Structural analysis and upgrades of microwave towers – DBP has proposed costs of $[redacted] million (dollar values of 31 December 2010) over the course of the 2011 to 2015 access arrangement period for structural analysis and upgrades of microwave towers. Halcrow & Zincara consider that this cost has not been justified as prudent, taking into account that the age of the towers is less than typical design lives and any upgrades necessary for a change in use of the towers should be considered as part of projects for the change in use. Halcrow & Zincara consider that the cost should be removed from the forecast of stay-in-business capital expenditure.[162]
- Upgrade of solar panels – DBP has proposed costs of $[redacted] (dollar values of 31 December 2010) in 2011 and $[redacted] (dollar values of 31 December 2010) over the years 2013 to 2015 for a FEED study and implementation for replacement of solar panels. Halcrow & Zincara consider the proposed works and overall cost to be reasonable, but question whether the cost for FEED study should be allowed for in 2011 rather than put back to 2012.[163]

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158 Halcrow & Zincara, pp. 95, 96.
159 Halcrow & Zincara, pp. 99, 100.
160 Halcrow & Zincara, pp. 108, 109.
161 Halcrow & Zincara, pp. 115, 116.
162 Halcrow & Zincara, pp. 117, 118.
163 Halcrow & Zincara, p. 119.

- Replacement of closed circuit vapour turbines – DBP has proposed costs of $[redacted] (dollar values of 31 December 2010) over the years 2011 to 2013 for a program of replacement of closed circuit vapour turbines that commenced in 2010. Halcrow & Zincara indicate that this program had an original estimated project cost of $[redacted] (nominal), of which $[redacted] (nominal) has been included in the statement of actual stay-in-business capital expenditure for 2010. Halcrow & Zincara consider that only the balance of this estimated cost ($0.8 million) should be provided for in forecast stay-in-business capital expenditure for the 2011 to 2015 access arrangement period.[164]
- Relocation of the disaster recovery system – DBP has proposed costs of $[redacted] in 2012 and $[redacted] in 2014 (dollar values of 31 December 2010) for a FEED study and implementation for relocation of the disaster recovery system to Kwinana. Halcrow & Zincara consider the proposed works and overall cost to be reasonable, but question whether the cost for FEED study should be allowed for in 2012 rather than put back to 2013.[165]
- Upgrade of security – DBP has proposed costs of $[redacted] (dollar values of 31 December 2010) over the years 2011 and 2014 for upgrades of security at facility sites. Halcrow & Zincara consider that DBP has provided inadequate information to justify the expenditure and recommend that the costs be excluded from the forecast of stay-in-business capital expenditure.[166]
- SCADA upgrade – DBP has included in the forecast of stay-in-business capital expenditure an amount of $[redacted] (dollar values of 31 December 2010) for a SCADA upgrade, but DBP subsequently advised Halcrow & Zincara that expenditure for these works would actually occur in 2010. Halcrow & Zincara thus recommend that this amount should be removed from the forecast of stay-in-business capital expenditure.[167]
- Computer purchases – DBP has proposed costs of $[redacted] (dollar values of 31 December 2010) over the 2011 to 2015 access arrangement period for computer purchases. Based on consideration of unit costs, Halcrow & Zincara consider the forecast cost to be excessive and recommend that a cost of $75,000 (dollar values of 31 December 2010) be included for each year, for a total of $375,000.[168]
- New vehicle purchases – DBP has proposed costs of $[redacted] (dollar values of 31 December 2010) in 2011 for new vehicle purchases. Halcrow & Zincara consider that DBP has provided inadequate information to justify the expenditure and recommend that the costs be excluded from the forecast of stay-in-business capital expenditure.[169]

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[164] Halcrow & Zincara, p. 120.

[165] Halcrow & Zincara, pp. 123.

[166] Halcrow & Zincara, pp. 126, 127.

[167] Halcrow & Zincara, p. 127.

[168] Halcrow & Zincara, pp. 129, 130.

[169] Halcrow & Zincara, p. 131.

- Project management retainer fee – DBP has proposed a cost of $2.31 million per year (dollar values of 31 December 2010) over the 2011 to 2015 access arrangement period for the project management retainer fee payable to Westnet Energy Services Pty Ltd under the terms of the Operating Services Agreement. Halcrow & Zincara consider that the value of the fee is excessive by industry standards and notes that there is a lack of provision for the value of the fee to be netted off against any actual project management fees that are payable.[170]

Table 16b Aggregate summary of redacted information (paragraph 289) Halcrow & Zincara assessment of DBP's forecast stay-in-business capital expenditure for the 2011 to 2015 (real $ million at 31 December 2010)

Proposed Costs (2011 – 2015)	DBP	Halcrow & Zincara
Capital Projects Accepted but reduced by Halcrow & Zincara		
Replacement of PVC oil waste pipes at compressors		
Replacement of underground pipework at compressor stations		
Replacement of water pipework at CS2		
Installation of gas chromatographs		
Upgrade of solar panels		
Replacement of closed circuit vapour turbines		
Relocation of the disaster recovery system		
Computer purchases		
Sub Total	**12.053**	**5.050**
Capital Projects Accepted but re-profiled by Halcrow & Zincara		
LM500 Compressor Units Decommissioning		
Relocation of microwave batteries		
Upgrade of solar panels		
Relocation of the disaster recovery system		
Sub Total	**0.169**	**0.169**
Capital Projects Excluded by Halcrow & Zincara		
Replacement of (CS6 Nova Pignone Compressor)		
Standardisation of turbine/compressor "control logic"		
Structural analysis and upgrades of microwave towers		
Upgrade of security		
SCADA upgrade		
New vehicle purchases		
Sub Total	**3.908**	**0.000**
Total	**16.130**	**5.219**

170 Halcrow & Zincara, pp. 137 – 139.

290. The analysis and advice of Halcrow & Zincara indicates to the Authority that:

- DBP has not provided sufficient information to demonstrate conformity with the prudence and efficiency requirement of rule 79(1)(a) for $22.308 million (dollar values of 31 December 2010) of stay-in-business capital expenditure; and
- For several projects and expenditure items, there is some evidence of front-loading of forecast expenditure in the access arrangement period, particularly for projects where there is a time delay between FEED studies and the projected undertaking of capital works.

291. Taking account of the above matters, the Authority is of the view that the forecast of stay in business capital expenditure does not conform to the prudence and efficiency requirement of rule 79(1)(a). The Authority will require amendment of this forecast to:

- remove the provision for the project management retainer fee, amounting to $2.311 million in each year to a total of $11.556 million (dollar values of 31 December 2010);
- remove provision for projects and expenditure items identified by Halcrow & Zincara for which insufficient supporting information has been provided to demonstrate conformity with the prudence and efficiency requirement of rule 79(1)(a), amounting to $10.752 million (dollar values of 31 December 2010).

292. The Authority's required amendment for forecast capital expenditure to be included in the projected capital base for the 2011 to 2015 access arrangement period is shown in Table 17. The amended forecast of conforming capital expenditure is $22.461 million (16.5 per cent) less than proposed by DBP (dollar values of 31 December 2010).

Table 17 Authority's required amended values of forecast conforming capital expenditure for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

Year	2011	2012	2013	2014	2015
Forecast Expenditure					
Pipeline	9.848	3.506	3.646	0.415	0.649
Compression	17.186	6.765	3.006	3.121	6.221
Metering	0.433	0.391	2.057	1.794	0.123
Other depreciable	38.374	3.825	3.220	4.564	4.903
Other non-depreciable	-	-	-	-	-
Total	**65.841**	**14.487**	**11.929**	**9.894**	**11.897**

Required Amendment 6

The forecast of conforming capital expenditure for the 2011 to 2015 access arrangement period must be amended to values shown in Table 17 of this draft decision.

Capital Contributions

293. The treatment of capital contributions in determining the capital base is guided by rule 82 of the NGR.

82 Capital contributions by users to new capital expenditure

(1) A user may make a capital contribution towards a service provider's capital expenditure.

(2) Capital expenditure to which a user has contributed may, with the AER's [ERA's] approval, be rolled into the capital base for a pipeline but, subject to subrule (3), not to the extent of any such capital contribution.

(3) The AER [ERA] may approve the rolling of capital expenditure (including a capital contribution made by a user, or part of such a capital contribution) into the capital base for a pipeline on condition that the access arrangement contain a mechanism to prevent the service provider from benefiting, through increased revenue, from the user's contribution to the capital base.

294. Clause 12 of the proposed revised access arrangement sets out a regulatory treatment of capital contributions made or to be made by shippers. DBP proposes to add funded capital expenditure to the capital base for the DBNGP and has included a mechanism to ensure that DBP does not benefit, through increased revenue, from the contributions by separately accounting for the funded capital expenditure so that these capital costs are excluded from charges for pipeline services.

295. DBP has indicated that it has or will receive capital contributions totalling $38.819 million (dollar values of 31 December 2010) over the 2005 to 2010 access arrangement period, and forecasts capital contributions of $4.437 million (dollar values of 31 December 2010) over the 2011 to 2015 access arrangement period (Table 18).

Table 18 DBP's stated actual and forecast capital expenditure contributed by shippers (real $ million at 31 December 2010)[171]

Year ending 31 December	Year	Year	Year	Year	Year	Year
2005 to 2010 Access Arrangement Period[172]	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 F/cast**
Pipelines	-	-	-	-	9.868	-
Compressors	-	-	-	-	-	-
Meters	2.245	-	0.086	-	11.887	14.655
Other depreciable	-	-	-	-	0.077	-
Non depreciable	-	-	-	-	-	-
Total	2.245	-	0.086	-	21.833	14.655
2011 to 2015 Access Arrangement Period[173]		**2011 F/cast**	**2012 F/cast**	**2013 F/cast**	**2014 F/cast**	**2015 F/cast**
Pipelines		-	-	-	-	-
Compressors		-	-	-	-	-
Meters		0.234	2.725	1.478	-	-
Other depreciable		-	-	-	-	-
Non depreciable		-	-	-	-	-
Total		0.234	2.725	1.478	-	-

296. The Authority has considered whether DBP's proposed treatment of capital contributions complies with the requirements of rule 82 of the NGR.

297. DBP's proposed treatment of capital contributions is to add the capital expenditure financed by capital contributions to the capital base for the DBNGP, but to separately account for the return on these amounts and the depreciation of these amounts, and to not allocate these amounts to any pipeline service.

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171 DBP, 12 April 2010, Tariff Model (DBNGP AA proposal tariff model confidential – Final–Amended_12Apr10.XLS)

172 DBP, 1 April 2010, Revised access arrangement information, section 6.6 (Table 10). Values converted to real dollars using the inflation factors of DBP as contained DBP's proposed Tariff Model.

173 DBP, 1 April 2010, Revised access arrangement information, section 7.5 (Table 12).

298. The Authority considers that the treatment of capital contributions proposed by DBP adds complexity to the financial accounting and financial calculations for determination of reference tariffs by requiring separate accounting of the portion of the capital base that corresponds to amounts of capital expenditure funded by capital contributions. The Authority would generally prefer for a simpler treatment of capital contributions, such as an exclusion from the capital base of capital expenditure financed by capital contributions. However, the Authority considers that the treatment proposed by DBP has the same ultimate outcome as excluding the amounts of capital expenditure funded by capital contributions from the capital base. The Authority is therefore satisfied that this treatment constitutes a mechanism that prevents DBP from benefiting, through increased revenue, from the capital contributions, and that the treatment is consistent with the requirements of rule 82.

299. Financial calculations for implementing DBP's proposed treatment of capital contributions must include separate capital accounts for capital expenditure that is financed by capital contributions. This enables returns on this expenditure and depreciation allowances to be correctly calculated and excluded from the amount of total revenue to be recovered by reference tariffs. DBP's financial calculations do not accord with this requirement. Without these separate capital accounts, it is not possible to ensure that the proposed treatment of capital contributions has been implemented correctly. The Authority's financial calculations for this draft decision correct the treatment of capital contributions and include separate capital accounts in the financial calculations of total revenue.

300. The Authority is not seeking any amendment to DBP's stated values of capital contributions. However, as a result of corrections to financial calculations there are minor revisions to the values of capital contributions expressed in dollar values of 2010. The corrected values are indicated in Table 19.

Table 19 Authority approved values of actual and forecast capital expenditure contributed by shippers (real $ million at 31 December 2010)

Year ending 31 December	Year	Year	Year	Year	Year	Year
2005 to 2010 Access Arrangement Period[174]	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 F/cast**
Pipelines	-	-	-	-	9.868	-
Compressors	-	-	-	-	-	-
Meters	2.245	-	0.086	-	11.887	14.655
Other depreciable	-	-	-	-	0.077	-
	-	-	-	-	-	-
Total	**2.245**	**-**	**0.086**	**-**	**21.833**	**14.655**
2011 to 2015 Access Arrangement Period[175]		**2011 F/cast**	**2012 F/cast**	**2013 F/cast**	**2014 F/cast**	**2015 F/cast**
Pipelines		-	-	-	-	-
Compressors		-	-	-	-	-
Meters		0.234	2.725	1.478	-	-
Other depreciable		-	-	-	-	-
		-	-	-	-	-
Total		**0.234**	**2.725**	**1.478**	**-**	**-**

301. One party that made a submission on the proposed revised access arrangement submitted that the grant of $88 million made by the Western Australian Government to the owners of the DBNGP under the October 2004 Financial Assistance Agreement should be treated similarly to capital contributions by users, and excluded from revenue calculations in a clear and transparent manner.[176]

302. The Authority considers that the grant should not be treated as a capital contribution for reasons that:

- the grant does not conform to a capital contribution as contemplated by rule 82, due to the contribution not being made by a user; and
- clawing back the benefit to DBP of the grant would be contrary to the likely intention of the grant when it was made (as a subsidy to DBP).

174 DBP, 1 April 2010, Revised access arrangement information, section 6.6 (Table 10). Values converted to real dollars using the inflation factors of DBP as contained DBP's proposed Tariff Model.

175 DBP, 1 April 2010, Revised access arrangement information, section 7.5 (Table 12).

176 Verve Energy, 9 July 2010.

Depreciation

303. Rule 88(1) of the NGR provides that the depreciation schedule sets out the basis on which the pipeline assets constituting the capital base are to be depreciated for the purpose of determining a reference tariff. Rule 88(2) of the NGR provides that the depreciation schedule may consist of a number of separate schedules, each relating to a particular asset or class of assets.

304. Rules 89 and 90 of the NGR specify particular depreciation criteria and requirements for the calculation of depreciation for establishing the opening capital base for the subsequent access arrangement period.

> 89 Depreciation criteria
>
> (1) The depreciation schedule should be designed:
>
> (a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and
>
> (b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and
>
> (c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and
>
> (d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the [Authority] permits, for inflation)); and
>
> (e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.
>
> (2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:
>
> (a) the present market for pipeline services is relatively immature; and
>
> (b) the reference tariffs have been calculated on the assumption of significant market growth; and
>
> (c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

(3) The AER's [ERA's] discretion under this rule is limited.

90 Calculation of depreciation for rolling forward capital base from one access arrangement period to the next

(1) A full access arrangement must contain provisions governing the calculation of depreciation for establishing the opening capital base for the next access arrangement period after the one to which the access arrangement currently relates.

(2) The provisions must resolve whether depreciation of the capital base is to be based on forecast or actual capital expenditure.

305. Clause 9 of the proposed revised access arrangement comprises provisions relating to the calculation of depreciation to establish the opening capital base for the access arrangement period commencing 1 January 2016. The provisions comprise principles that include:

- determining separate depreciation schedules for four groups of asset classes: pipeline assets, compressor station assets, metering assets and other assets;
- applying a straight-line depreciation method; and
- depreciating each group of assets over the economic life of that group.

306. Section 6.7 of the revised access arrangement information sets out the values of depreciation allowances over the 2005 to 2010 access arrangement period, as used to determine the opening capital base for the 2011 to 2015 access arrangement period. The Authority observes that the values indicated in the revised access arrangement information comprise only amounts of depreciation relating to values of assets included in the opening capital base for the DBNGP at the commencement of the 2005 to 2010 access arrangement period, and do not include amounts of depreciation allowances calculated from forecast capital expenditure for that access arrangement period. The total values of depreciation allowances have been presented in DBP's proposed tariff model and are shown in Table 20 (expressed in dollar values of 2010).

Table 20 DBP proposed values of depreciation allowances for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[177]

Year ending 31 December	2005	2006	2007	2008	2009	2010
Pipelines	33.379	33.479	37.894	42.651	44.103	50.764
Compression	15.324	18.112	22.865	24.503	24.519	34.356
Metering	0.752	0.736	0.785	0.784	0.785	1.045
Other depreciable	4.619	4.748	4.812	5.034	5.298	7.994
Non depreciable	-	-	-	-	-	-
Total	**54.073**	**57.074**	**66.356**	**72.971**	**74.705**	**94.159**

177 DBP, 12 April 2010, Tariff Model (DBNGP AA proposal tariff model confidential – Final–Amended_12Apr10.XLS).

307. DBP indicates in the revised access arrangement information that it has calculated values of depreciation for the 2011 to 2015 access arrangement period by:

- depreciation of the asset values of the initial capital base established at 1 January 2000 by a straight-line depreciation calculation over average remaining asset lives established at that date of:
  - 54.5 years for pipeline assets;
  - 19.34 years for compression assets;[178]
  - 39.98 years for metering assets;[179]
  - 16.85 years for other depreciable assets; and
- depreciation of the asset values resulting from capital expenditure subsequent to 1 January 2000 by a straight-line depreciation calculation over asset lives of:
  - 70 years for pipeline assets;
  - 30 years for compression assets ;
  - 50 years for metering assets, and
  - 30 years for other depreciable assets.

308. Values of depreciation allowances for the 2011 to 2015 access arrangement period are set out in sections 7.7 to 7.14 of the revised access arrangement information. These values, expressed in dollar values of 2010, are shown in Table 21. These values are consistent with values applied in DBP's proposed tariff model.

Table 21 DBP proposed values of depreciation allowances for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[180]

Year ending 31 December	2011	2012	2013	2014	2015
Pipelines	51.131	51.254	51.311	51.378	8.017
Compression	34.639	34.656	34.747	34.838	0.159
Metering	1.108	1.541	1.617	1.654	0.837
Other depreciable	9.395	9.557	9.699	9.930	6.318
Non depreciable	-	-	-	-	-
Total	**96.273**	**97.008**	**97.374**	**97.801**	**15.331**

178 It is noted that DBP's proposed revised tariff model uses a value of 18.72 years.

179 It is noted that DBP's proposed revised tariff model uses a value of 38.01 years.

180 DBP, 1 April 2010, Revised access arrangement information, section 7.14 (Table 14). DBP, 12 April 2010, Tariff Model (DBNGP AA proposal tariff model confidential – Final–Amended_12Apr10.XLS).

309. The Authority has assessed the values of depreciation allowances derived by DBP to verify that the allowances have been determined consistently with the method and assumptions stated in the access arrangement information. The Authority has also recalculated values of depreciation allowances for the 2011 to 2015 access arrangement period in accordance with other required amendments to the calculation of total revenue under this draft decision.

310. For depreciation allowances in the 2005 to 2010 access arrangement period, the relevant matter for assessment is whether the values applied in the roll-forward calculation of the capital base are the same (i.e. are equivalent in real terms) as the values of depreciation allowances applied in the determination of total revenue and reference tariffs for this access arrangement period. The Authority is satisfied that this is the case, subject to changes to the calculations applied to escalate the values for inflation and expression of amounts in real dollar values of 31 December 2010 (as set out in paragraph 102 and following of this draft decision).

311. For depreciation allowances in the 2011 to 2015 access arrangement period, the relevant matters for assessment are:

- whether the method and assumptions of depreciation schedules continue to meet the requirements of rules 88 and 89 of the NGR; and
- whether the values of depreciation allowances have been calculated correctly according to the depreciation schedules.

312. DBP's straight-line method for determination of depreciation allowances and the assumed asset lives are consistent with the method and assumptions applied in previous access arrangement periods. The Authority considers that this method and the assumed asset lives meet the requirements of rules 88 and 89 of the NGR. The Authority considers that no factors have emerged over the course of the 2005 to 2010 access arrangement period that warrant reconsideration of the depreciation methods or assumptions against the design criteria for depreciation schedules set out in rule 89.

313. Notwithstanding that the depreciation schedules meet the requirements of rules 88 and 89 of the NGR, the Authority considers that DBP has not correctly implemented the depreciation schedules in determining depreciation allowances for the 2011 to 2015 access arrangement period.

314. The standard calculation method for determining depreciation allowances is to maintain separate asset accounts for the values of the initial capital base and for the capital expenditure of each year. This allows the residual value of assets to be tracked over time and for depreciation allowances for either the initial capital base or the capital expenditure in any particular year to be set to zero when the asset value is fully depreciated.

315. DBP has not applied this standard calculation method, but rather has used a "short-cut" calculation to calculate depreciation allowances for each asset class over the 2011 to 2015 access arrangement period by:

- for 2011,
  - taking the depreciation allowance applied for the 2004 year and escalating this for inflation;
  - calculating a value of depreciation allowances for capital expenditure in the 2005 to 2010 access arrangement period by dividing the total amounts of capital expenditure by an assumed asset life for new assets

(70 years for pipeline assets, 30 years for compression assets, 50 years for metering assets, 30 years for other depreciable assets); and

- for each subsequent year,
  - taking the value of the depreciation allowance for the previous year; and
  - adding an amount of depreciation for new capital expenditure in that previous year, calculated by dividing the total amounts of capital expenditure by an assumed asset life for new assets (70 years for pipeline assets, 30 years for compression assets, 50 years for metering assets, 30 years for other depreciable assets).

316. DBP's calculation does not allow the residual value of assets to be tracked over time and allows for the possibility of over-depreciation of assets, i.e. determination of depreciation allowances without allowing for values of assets in some type and age classes having been reduced to zero.

317. The Authority has corrected the calculation of depreciation allowances and, as well, revised the calculation to take into account required amendments to other elements of calculation methods and values of conforming capital expenditure as set out elsewhere in this draft decision.

318. There are three further matters that the Authority has addressed in the determination of depreciation allowances.

319. First, due to differences between forecast and actual capital expenditure in the 2005 to 2010 access arrangement period (Table 12), the depreciation allowances in this period have resulted in "over-depreciation" of some asset categories for some years of capital expenditure. The Authority has corrected for this in financial calculations. This is a financial calculation issue only and has no impact on the value of total revenue and reference tariffs.

320. Secondly, the Authority has included amounts in depreciation allowances in respect of the forecast capital expenditure on the BEP Capacity (refer to paragraph 151 and following of this draft decision). The Authority considers that the capital value of the BEP Capacity should be depreciated in accordance with the depreciation schedule for pipeline assets. However, the BEP is an existing pipeline constructed in c.1999 and does not have the same asset life as new pipeline assets. The Authority has calculated depreciation allowances for the BEP capacity as a separate asset class assuming a total asset life of 60 years. This is consistent with the terms of the lease of the BEP Capacity (an initial lease term of 20 years and option for extension for an additional 40 years) and the consideration of DBP that this lease term is equal to remaining physical life of the pipeline assets of the BEP.[181]

321. Thirdly, the Authority has separately calculated depreciation allowances for capital expenditure that has been financed by capital contributions, consistent with DBP's treatment of capital contributions and the need to maintain separate regulatory asset accounts to implement this treatment.

181 DBP, Submission #37, Attachment 3 item 12.

322. The corrected and revised values of depreciation allowances are shown in Table 22.

Table 22 Corrected and revised values of depreciation allowances for the 2005 to 2010 and 2011 to 2015 access arrangement periods (real $ million at 31 December 2010)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Pipelines	32.535	32.611	32.709	37.022	41.671	43.089
Compression	14.894	14.972	17.695	22.339	23.939	23.955
Metering	0.708	0.734	0.764	0.767	0.767	0.767
Other depreciable	4.354	4.512	4.638	4.701	4.918	5.176
Non depreciable	-	-	-	-	-	-
Total	**52.490**	**52.830**	**55.806**	**64.830**	**71.295**	**72.987**
Year ending 31 December		**2011**	**2012**	**2013**	**2014**	**2015**
Pipelines		49.798	49.938	49.988	50.040	50.046
Compression		31.993	32.566	32.791	32.892	32.996
Metering		0.714	0.722	0.730	0.771	0.807
Other depreciable		6.982	8.261	8.389	8.496	8.648
Non depreciable		-	-	-	-	-
Total		**89.486**	**91.487**	**91.898**	**92.199**	**92.497**

Values of the Capital Base

323. The Authority has recalculated the value of the opening capital base and projected capital base for the 2011 to 2015 access arrangement period taking into account the corrections to calculations and the required amendments to conforming capital expenditure and depreciation allowances (Table 23 and Table 24). Given DBP's proposed treatment of capital contributions (where the contributions are added to the capital base, but quarantined from determination of total revenue) the capital base is shown as a total value and a breakdown into the component asset accounts for "DBP assets" and capital contributions.

Table 23 Authority's revised calculation of the opening capital base for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

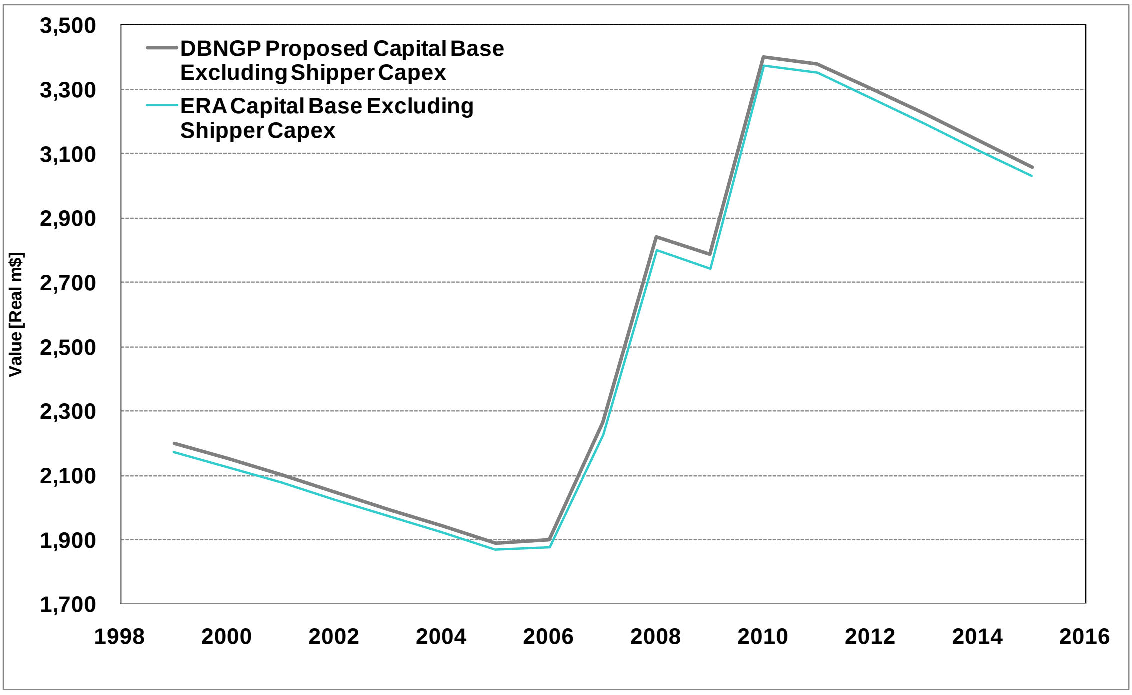
Year ending 31 December	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast
Total Capital Base						
Capital Base at 1 January	1,922.162	1,872.710	1,877.593	2,227.148	2,804.222	2,766.226
plus						
Conforming Capital Expenditure	0.793	57.713	405.274	641.905	11.466	699.931
Forecast Capital Contributions	2.245	-	0.086	-	21.833	14.655
Correction for over-depreciation	-	-	-	-	-	6.014
less						
Redundant and disposed assets	-	-	-	-	-	-
Depreciation	52.490	52.830	55.806	64.830	71.295	72.987
Capital base at 31 December	**1,872.710**	**1,877.593**	**2,227.148**	**2,804.222**	**2,766.226**	**3,413.839**
DBNGP assets						
Capital Base at 1 January	1,922.162	1,870.465	1,875.348	2,224.816	2,801.891	2,742.062
plus						
Conforming Capital Expenditure	0.793	57.713	405.274	641.905	11.466	699.931
Forecast Capital Contributions	-	-	-	-	-	-
Correction for over-depreciation	-	-	-	-	-	6.014
less						
Redundant and disposed assets	-	-	-	-	-	-
Depreciation	52.490	52.830	55.806	64.830	71.295	72.987
Capital base at 31 December	**1,870.465**	**1,875.348**	**2,224.816**	**2,801.891**	**2,742.062**	**3,375.020**
Capital contributions						
Capital Base at 1 January	-	2.245	2.245	2.331	2.331	24.164
plus						
Conforming capital expenditure	-	-	-	-	-	-
Capital contribution	2.245	-	0.086	-	21.833	14.655
Correction for over-depreciation	-	-	-	-	-	-
less						
Redundant and disposed assets	-	-	-	-	-	-
Depreciation	-	-	-	-	-	-
Capital base at 31 December	**2.245**	**2.245**	**2.331**	**2.331**	**24.164**	**38.819**

Table 24 Authority's revised calculation of the projected capital base for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

Year	2011	2012	2013	2014	2015
Total capital base					
Capital Base at 1 January	3,413.839	3,389.408	3,314.106	3,234.534	3,151.119
plus					
Forecast Conforming Capital Expenditure	65.841	14.487	11.929	9.894	11.897
Forecast Capital Contributions	0.234	2.725	1.478	-	-
Correction for over depreciation	-	-	-	-	-
less					
Redundant and disposed assets	-	-	-	-	-
Depreciation	90.507	92.513	92.979	93.309	93.607
Capital Base at 31 December	**3,389.408**	**3,314.106**	**3,234.534**	**3,151.119**	**3,069.409**
DBNGP assets					
Capital Base at 1 January	3,375.020	3,351.087	3,273.798	3,193.541	3,110.948
plus					
Conforming Capital Expenditure	65.841	14.487	11.929	9.894	11.897
Forecast Capital Contributions	-	-	-	-	-
Correction for over depreciation	-	-	-	-	-
less					
Redundant and disposed assets	-	-	-	-	-
Depreciation	89.774	91.775	92.186	92.487	92.785
Capital base at 31 December	**3,351.087**	**3,273.798**	**3,193.541**	**3,110.948**	**3,030.060**
Capital contributions					
Capital Base at 1 January	38.819	38.320	40.307	40.993	40.171
plus					
Conforming Capital Expenditure	-	-	-	-	-
Forecast Capital Contributions	0.234	2.725	1.478	-	-
Correction for over depreciation	-	-	-	-	-
less					
Redundant and disposed assets	-	-	-	-	-
Depreciation	0.733	0.738	0.792	0.822	0.822
Capital base at 31 December	**38.320**	**40.307**	**40.993**	**40.171**	**39.349**

324. The effect of the Authority's draft decision on the value of the capital base for the DBNGP is relatively small, as shown in Figure 4. The Authority's financial model, released with this draft decision (Appendix 5), contains details of the Authority's calculation of the opening capital base for the current access arrangement period based on the Authority's approved escalation rate.

Figure 4 Proposed and draft decision values of the capital base for the DBNGP



Rate of Return

Regulatory Requirements

325. Rule 87 of the NGR specifies particular requirements for the rate of return.

87 Rate of return

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

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

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

(i) meets benchmark levels of efficiency; and

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

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

Approach to Determination of the Rate of Return

DBP's Proposed Revisions

DBP's interpretations of the National Gas Rules 87(1) and 87(2)

326. DBP submits that rule 87(1) involves two distinct criteria for the rate of return.

- First a requirement that the rate of return on capital be commensurate with prevailing conditions in the market for funds. DBP argues that the relevant market for funds is the international capital market, given the scale of the operations of the business.[182]
- Second, there is a risk involved in providing the reference services, which reflects legislative recognition of the difference between risks which affect all participants in the market for funds (or generic risks), and risks which affect the provider of reference services (risks to the particular service provider).[183]

327. DBP also argues that operating in the Western Australian gas market exposes the operator to commercial risks that are additional to and different from those faced by operators in the eastern states gas markets.

328. DBP argues that rule 87(2) does not prescribe the application of a calculation that provides a uniquely correct answer. DBP considers that Rule 87(2) outlines a flexible approach which guides the determination of a rate of return on capital.[184]

"Benchmark levels of efficiency" or "benchmark standards"

329. DBP submits that rule 87(2)(a) requires two assumptions:

- first, the benchmark levels of efficiencies; and
- second, the financing structures, requires an assessment (or assumption) as to benchmark gearing ratios and other financial parameters for a going concern and what constitutes best practice.

330. DBP notes that the above assumptions required are themselves based on assumptions and assessments.

331. DBP argues that rule 87(2)(a) gives rise to a number of interpretational issues. The first interpretational issue relates to the context in which the provisions are construed.

332. DBP submits that the values or principles for rate of return parameters that have been set by regulators for regulated electricity businesses under the National Electricity Law, such as the 2009 weighted average cost of capital (**WACC**) Review by the Australian Energy Regulator (**AER**), are not appropriate to be used as reference points for either the term "benchmark levels of efficiency" or "benchmark standards" under Rule 87(2)(a) for the following reasons.

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182 DBNGP Revised Access Arrangement Proposal Submission, p. 6.

183 DBNGP Revised Access Arrangement Proposal Submission, p. 6.

184 Section 5.1 of DBNGP Revised Access Arrangement Proposal Submission, p. 8.

333. First, the AER acknowledged that the National Electricity Rules do not define a "benchmark efficient" service provider. DBP argues that relying on values that have been set by regulators for an electricity transmission and distribution businesses in any Australian market on the basis that the values are a proxy for benchmark levels of efficiency in relation to a gas transmission business in Western Australia is not supported, as doing so would produce a result that is contradictory to the requirement of rule 87(1) of the NGR.

334. Second, DBP argues that, under the National Electricity Law, the concept of "benchmark efficiency" appears to be one of "benchmark financial efficiency", because the considerations to which the concept is to be applied are all measures of financial structure or environment. However, DBP states that, under rule 87(2) of the NGR, "benchmark levels of efficiency" and "benchmark standards as to gearing and other financial parameters" are separate concepts; and that the concept of benchmark in relation to financial parameters is limited to "gearing and other financial parameters for a going concern".

335. Third, DBP submits that the use of the WACC and the Capital Asset Pricing Model (**CAPM**) are mandatory under the National Electricity Rules, whereas this is not the case under the NGR.

336. Fourth, DBP states that the central aim for benchmark efficiency under the National Electricity Rules is to achieve competitive neutrality of tariff setting from the AER's view. DBP questions whether the same can be said in relation to the NGR because it appears a far more subjective approach is contemplated in relation to a range of matters.[185]

337. As a result, DBP challenges the assumption that values that have been set by regulators for an electricity transmission or distribution business in any other Australian state can be used as a proxy for benchmark levels of efficiency in relation to a gas transmission business in Western Australia.

338. The second interpretational issue in DBP's submission is that Rule 87(2)(a)(i) addresses issues such as operational efficiency and efficiency in raising and utilisation of capital.[186]

339. The third interpretational issue is that the financing structure must be benchmarked in certain aspects such as gearing and other financial parameters for a going concern.[187]

340. In summary, DBP questions whether Rule 87(2)(a) requires that the WACC parameters such as the nominal risk free rate, the equity beta, the market risk premium and credit rating levels to be applied to DBNGP should be based on an assumed benchmark.

185 Section 5.11 of DBNGP Revised Access Arrangement Proposal Submission, p. 9.

186 Section 5.12 of DBNGP Revised Access Arrangement Proposal Submission, p. 9.

187 Section 5.14 of DBNGP Revised Access Arrangement Proposal Submission, p. 9.

“Well accepted approach” and “well accepted financial model”

341. DBP argues that rule 87 describes a method of determination of the rate of return that necessarily involves a process of analysis and assessment of general market conditions and the risks relevant to the particular service provider.[188]

342. DBP also submits that it is necessary to consider the inherent ability of a “well accepted financial model” to produce a rate of return that is commensurate with prevailing market conditions and the peculiar risk which the service provider faces in providing the relevant reference services.

343. DBP also argues that, for the cost of equity, the rule does not require that the service provider only uses the CAPM; rather, it requires the identification of an appropriate approach to determining the cost of equity.[189] As such, DBP argues that rule 87 permits a variety of approaches to be used, as long as they are well accepted.

344. DBP acknowledges that the meaning of “well accepted” has proven problematic. DBP argues that it is not intended by the legislation that the model cannot be regarded as “well accepted” only because Australian regulators have not endorsed it. DBP considers that all financial models of this kind have their origins in academic theory; all have been applied with differing degrees of success in commerce; and all continue to be the subject of continued academic discourse and refinement.[190]

Submissions

345. BHP Billiton submitted that DBP has minimal exposure to market risk.[191] This view is based on the following observations.

- There is clear evidence that the DBNGP has continued to perform well despite the Global Financial Crisis, as there have been increases in transmission revenue and total capacity in 2008 and 2009.
- Given the high proportion of the fixed charge from the DBNGP, this results in a reduced cost of equity relative to the market, to reflect DBP’s reduced volume and price sensitivity.
- A high level of DBNGP’s revenue is on a take-or-pay basis, which ensures stable and predictable revenues.
- The majority of the DBNGP’s capacity is contracted to large, stable groups with strong balance sheets and/ or good credit ratings, such as BHP Billiton, Alcoa, ERM Power, Sumitomo Corporation, Wesfarmers and Verve Energy.

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188 Section 5.17 of DBNGP Revised Access Arrangement Proposal Submission, p. 10.

189 Section 5.19 of DBNGP Revised Access Arrangement Proposal Submission, p. 10.

190 Section 5.20 of DBNGP Revised Access Arrangement Proposal Submission, p. 10.

191 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 12-14.

346. Wesfarmers submitted that the risk profile faced by DBP is low given DBP's approach of not building any uncontracted capacity.[192] Other WA pipelines face much higher commodity and counterparty risks than DBP, particularly when most end users of the services provided by DBP do not have any reasonably available energy alternatives.

347. Verve Energy submitted that the rate of return proposed by DBP (nominal pre-tax WACC of 13.55% and real pre-tax WACC of 10.76%) is extremely high compared to the AER's final decision on the NSW gas distribution network of 9.69% (nominal vanilla WACC) in June 2010 and to the Authority's final decision on the GGP of 7.78% (real pre-tax WACC) in April 2010. Verve Energy was of the view that the return from the DBNGP is at less risk than the return from either of these two assets, because of the small number of high credit-worthy shippers, who all pay capacity reservation charges in advance. As such, Verve Energy submitted that the rate of return required from the DBNGP should be less than the rate of return from the NSW gas distribution asset.[193]

Considerations of the Authority

The relevant market for funds

348. The Authority does not agree with DBP's proposal that the rate of return on capital is required to be commensurate with prevailing conditions in the market for funds and that the relevant market is the international capital market, given the scale of the operations of the business. One of the key areas of debate in the Australian regulatory literature is the extent to which foreign investors should be recognised when the WACC parameters, such as the nominal risk free rate, the debt risk premium, the market risk premium, the equity beta of the regulated businesses, and the value of imputation credits, are estimated. These estimates are likely to be affected by the choice of a domestic CAPM or international CAPM.

349. In its WACC Review in 2009, the AER proposed to continue using the Officer WACC framework because this framework is consistent with past Australian regulatory practice and is accepted by finance practitioners. The AER considers that the relevant market for funds for a benchmark service provider needs to be relevant to the reference services, and the relevant market for funds in Australia. In addition, the WACC Review also notes that a domestic (not international) market model matches observed conditions in the Australian financial market and that all financial parameters in WACC calculations must be estimated on a consistent basis.[194]

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[192] Wesfarmers Chemicals, Energy and Fertilisers, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, p. 4.

[193] Verve Energy, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 11-13.

[194] Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. 97-101.

350. The Authority also does not agree with DBP's proposal that regulated businesses that operate in the Western Australian gas market are exposed to commercial risks that are additional to and different from those which operators in the Eastern States gas markets face. Given information made available to the Authority, including that which is set out in BHP Billiton's submission,[195] the Authority is of the view that DBP's argument has not been substantiated.

"Benchmark levels of efficiency" or "benchmark standards"

351. In its 2009 WACC Review, the AER considered that benchmark levels of efficiency mean that the return on capital should be a benchmark return, not the return on capital for the specific circumstances of the service provider. In addition, the AER also notes that the benchmark levels of efficiency are determined in relation to a notional benchmark service provider. The benchmark efficient network service provider is defined as a 'pure–play' regulated network business operating within Australia without parent ownership.[196] The Authority agrees with the AER's view on the issue and adopts it for the purpose of its assessment of DBP' proposed access arrangement.

A well accepted financial model

352. The Authority agrees with DBP's submission that the NGR recognises that alternative, well accepted financial models may be used. In addition, the Authority notes that the NGR states that the CAPM (usually known as Sharpe-Lintner CAPM[197]) is a well accepted financial model.

Method for Calculation of Rate of Return

DBP's Proposed Revisions

353. DBP proposes that the Rate of Return used in determining the total revenue and reference tariffs for the revisions to the access arrangement be determined as a real pre-tax weighted average of the returns applicable to debt and equity. DBP also notes that the NGL and the NGR do not preclude use of a real pre-tax WACC.[198]

The Nominal Post-Tax WACC Formula:

354. In the absence of an imputation tax system, the nominal post-tax form of the WACC is expressed below:

$$WACC_{\text{nominal post-tax}} = E\left(R_e\right)\times\frac{E}{V}\times + E\left(R_d\right)\times\frac{D}{V}\left(1-T_c\right)$$

195 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 12-14.

196 Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. 77-82.

197 Lawriwsky, M., 2008, The origins of the CAPM and its application in commercial practice and economic regulation. A report to the Essential Services Commission of Victoria

198 Section 6.4 of DBNGP Revised Access Arrangement Proposal Submission, p. 11.

where:

- $E(R_e)$ is the nominal post-tax expected rate of return on equity - the cost of equity;
- $E(R_d)$ is the nominal pre-tax expected rate of return on debt - the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt);
- D/V is the proportion of debt in the total financing; and
- T_c is the tax rate.

355. The Australian tax system provides credits to shareholders for tax already paid at the corporate level, to avoid double taxation of the same income stream. In this circumstance, the nominal post-tax WACC formula needs to be modified to reflect the additional element of shareholders' return available through the taxation system. This is an estimate of the post-tax return on assets in the presence of an imputation credit tax system:

$$WACC = E(R_e) \times \frac{E}{V} \times \frac{1 - T_c}{(1 - T_c(1-\gamma))} + E(R_d) \times \frac{D}{V}(1 - T_c)$$

where γ (gamma) is the value of franking credits created (as a proportion of their face value).

The Nominal Pre-Tax WACC Formula:

356. This is an estimate of the pre-tax return on assets, which can be obtained by dividing the right hand side of the formula for the above nominal post-tax return on assets by the component $(1 - T_c)$, which can be expressed as:

$$WACC = E(R_e) \times \frac{E}{V} \times \frac{1_c}{(1 - T_c(1-\gamma))} + E(R_d) \times \frac{D}{V}$$

The Real Pre-Tax WACC Formula:

357. A real pre-tax WACC is obtained by removing expected inflation π_e from the nominal pre-tax WACC:

$$WACC_{\text{real pre-tax}} = \frac{(1 + WACC_{\text{nominal pre-tax}})}{1 + \pi_e} - 1$$

Submissions

358. The Authority did not receive any public submissions in relation to the method of calculation of the rate of return.

Considerations of the Authority

359. While all regulators of utility industries in Australia use the CAPM to estimate the cost of capital, there is no clear precedent on the form of the WACC to be used (i.e. pre-tax or post-tax, real or nominal).

- A pre-tax real WACC has been generally preferred by the Independent Pricing and Regulatory Tribunal of New South Wales (**IPART**) and the Independent Competition and Regulatory Commission (**ICRC**) of the Australian Capital Territory.
- The ACCC and the AER have used a post-tax nominal form of the WACC in recent decisions.
- The Essential Services Commission of Victoria (**ESC**) has used a post-tax real form of the WACC in recent decisions.

360. The Authority notes that DBP's proposed method of ascertaining a rate of return using a real pre-tax WACC is appropriate and this proposal is also consistent with the Authority's preference. The Authority is therefore satisfied that the proposed method of calculating the rate of return using a real pre-tax WACC formula meets the requirements of the NGL and NGR.

361. The Authority also prefers a real pre-tax WACC approach, as this method:

- simplifies financial modelling;
- is consistent with the preferences of major utilities in Western Australia (e.g. Water Corporation and Western Power); and
- allows consistency across regulated utilities in Western Australia.

Methods for Estimating the Cost of Equity

DBP's Proposed Revisions

362. DBP submits that rule 87(2) does not require that the service provider only use the CAPM to estimate the cost of equity. DBP argues that the rule permits a variety of approaches to be used, as long as they are well accepted. DBP also argues that the term "Capital Asset Pricing Model" is not defined in the NGL or in the NGR.[199]

363. As a result, DBP submits four different CAPM models, known as:

- Sharp-Lintner CAPM;
- Black's CAPM;
- Fama-French CAPM; and
- Zero-beta Fama French CAPM

364. Each of these four pricing models is briefly discussed in turn below.

199 DBNGP Revised Access Arrangement Proposal Submission, p. 12.

365. In addition, DBP argues that the Fama-French CAPM and the zero-beta Fama-French CAPM were developed on the grounds of Merton's theory of inter-temporal choice. DBP also briefly discusses this theory.

366. The above four CAPM models are discussed from two different perspectives.

- First, there is the theoretical background to the model. This "theoretical" background does not imply that there is a theory in which the model was developed. It simply implies the source of the model developed from the original academic papers.
- Second, there is the practical application of the model. Academic studies are conducted to examine the validity of the models developed, wherever relevant to DBP's submissions.

367. The next section is devoted to the analyses of practical applications, submitted by DBP and its consultants on the issue. A theoretical discussion of the four CAPM models is provided as Appendix 3 of this draft decision.

Black CAPM

368. To estimate the cost of equity, the Black CAPM requires a risk free rate, an estimate of the zero-beta premium, an equity beta and a market risk premium. Except for the zero-beta premium, all other parameters are the same as those used in the Sharpe-Lintner CAPM.

369. NERA Economic Consulting (**NERA**) presents a summary of existing evidence on the Black CAPM, including four studies for the US (in the form of the formal publications) and one study (in the form of a working paper) for Australia as shown in Table 25.[200]

[200] DBNGP Revised Access Arrangement Proposal Submission: Supporting document from NERA – The required rate of returns on equity for a gas transmission pipeline.

Table 25. Summary of existing evidence on the Black CAPM

Study	Period	Zero-beta premium (standard error in brackets)
	US evidence:	
Fama and MacBeth (1973) [201]	1935-1968	5.76 (2.28)
Campbell (2004) [202]	1929-1963	2.76 (3.36)
Lewellen, Nagel and Shanken (2008)[203]	1963-2004	11.60 (3.65)
Campbell (2004) [204]	1963-2001	8.28 (3.12)
	Australia evidence:	
Lajbcygier and Wheatley (2009) [205]	1979-2007	9.96 (2.04)

Source: NERA's Report (March 2010)

370. NERA submits that the mean return to a zero-beta asset, which is 7.67 per cent per year[206] from Table 25, has been substantially above the risk-free rate, which is contrary to the prediction of the Sharp-Lintner CAPM.

Fama-French three-factor Model (FFM)

371. NERA argues that the FFM is better at predicting the return on stocks than the Sharpe-Lintner CAPM, for the following two reasons.[207]

201 Fama, E and J. MacBeth, Risk, return, and equilibrium: Empirical tests, *Journal of Political Economy* 71, pp. 607-636.

202 Campbell, J. And T. Vuolteenaho, Bad beta, good beta, *American Economic Review* 94, pages 1249-1275.

203 Lewellen, J., S. Nagel and J. Shanken, A sceptical appraisal of asset pricing tests, *Journal of Financial Economics*, forthcoming.

204 Campbell, J. And T. Vuolteenaho, Bad beta, good beta, *American Economic Review* 94, pages 1249-1275.

205 Lajbcygier, P. and Wheatley, S. (2009), Dividend Yield, Imputation Credits and Returns, Working Paper, Monash University.

206 $(5.76 + 2.76 + 11.60 + 8.28 + 9.96)/5 = 7.67.$

207 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from NERA – The required rate of returns on equity for a gas transmission pipeline, pp. 21-24.

372. First, NERA is of the view that the Fama and French (1993)[208] study shows that the Sharpe-Lintner CAPM is unable to explain the returns for firms with low market capitalisation and firms with high book-to-market ratios. Using data for 25 portfolios from Ken French's website, NERA submits that small firms with high book-to-market values have had alphas[209] of six per cent per year in the last 83 years (from 1927 to 2009) relative to the Sharpe-Lintner CAPM, whereas these portfolios deliver only one per cent per year difference relative to the FFM over the same period.

373. Second, NERA submits that the O'Brien, Brailsford and Gaunt (2008) study[210] finds similar results with a time series of Australian data, and that the Fama-French model tends to produce smaller pricing errors than does the Sharp-Lintner CAPM.

A well accepted financial model

374. DBP submits that inter-temporal capital asset pricing is a well accepted financial model, and that the Sharp-Lintner CAPM, the Black CAPM, the FFM and the zero-beta FFM are all well accepted. DBP notes that each model is well accepted for different reasons and acceptance does not necessarily mean that the model is without defects.

Submissions

375. Verve Energy submitted that DBP is contractually bound in its arrangements with T1 Shippers under the 2004 Contractual Arrangements or the SSC to use the CAPM to calculate the cost of equity in determining the applicable rate of return.[211]

376. In addition, Verve Energy also highlighted that the proposed cost of equity of 13.5 per cent by DBP does not utilise any well accepted financial models, and is purely based on "empirical evidence", including undisclosed equity analysts that support a cost of equity of 13 to 14 per cent.[212]

Considerations of the Authority

Empirical studies of the CAPM models in academic literature

377. The Authority assessed the validity of the argument put forward by DBP on its submissions in relation to the use of the Black CAPM and the Fama-French CAPM.

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208 Fama, Eugene and Kenneth French, Common risk factors in the returns to stocks and bonds, *Journal of Financial Economics* 33, 1993, p. 35.

209 An asset's alpha is a measure of the error with which a model prices the asset. It is the difference between the mean return to the asset and the return the model predicts the asset should earn on average. If an asset has a positive (negative) alpha, the model underestimates (overestimates) the return the market requires the asset earn. As a general guide, a model that produces large alphas is a model that will produce poor estimates of the cost of equity.

210 O'Brien, Michael, Tim Brailsford and Clive Gaunt, Size and book-to-market factors in Australia, Table 3, Electronic copy available at: http://ssrn.com/abstract=1206542.

211 Verve Energy, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 11-13.

212 Verve Energy, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 11-13.

Black CAPM

378. The Authority considers that four academic papers and one working paper do not constitute a significant body of evidence. A report prepared by NERA on the issue does not provide an explanation of how these four papers were selected, or even a justification of why these particular papers represent the opinion of a sufficient cross section of the academic literature participant class. In addition, four out of five academic papers presented were for the US capital market, whereas the relevant regulatory framework is concerned with Australian capital markets. As such, the Authority is of the view that the evidence presented does not reflect prevailing market conditions in which the reference services are provided to meet the requirements of rule 87(1) of the NGR.

379. In addition, for regulatory certainty, the Authority rejects the use of the estimate of the zero-beta premium from Lajbcygier and Wheatley (2009) paper as it is only a working paper from Monash University and the paper has not yet been through the rigorous process generally required of a formal publication. As such, the findings should not be considered as being as reliable as findings from other papers in well known academic journals. The Authority is not aware of any empirical studies published in academic journals regarding the estimates of zero-beta premium for Australia or any commercial sources in which estimates of zero-beta premium are available.

380. The Authority has not identified any evidence that the Black CAPM has been broadly applied by financial analysts and business practitioners in valuation or capital budgeting in Australia.

Fama-French three-factor Model (FFM)

381. The Authority considers each of these two papers presented in NERA's submission in turn below.

382. First, the Authority notes that the 1993 Fama-French paper established the FFM. The Authority is of the view that the relevant regulatory framework is the Australian capital market, whereas this study used US data which does not represent the prevailing market conditions for Australian firms. In addition, this empirical study is now almost 20 years old. During this period, many academic papers have employed different datasets, in different periods of time to test the validity of the FFM for Australia. No consistent conclusion has been reached. This argument will be further explored in the following section "Estimates of the cost of equity". As such, the Authority is of the view that practical applicability of the FFM is, to some extent, limited for the purpose of estimating a forward-looking rate of return for DBP.

383. Second, the Authority considers the working paper by O'Brien, Brailsford and Gaunt in 2008. In this paper, 25 portfolios were formed, in a manner similar to Fama and French (1993), on the basis of firm size and book-to-market ratios. The paper then examined the performance of the Sharpe-Lintner CAPM and FFM in measuring the returns required on the portfolios over the 25-year period from 1982 through to 2006.

384. As previously indicated, the Authority is of the view that peer reviewed academic papers should be given more weight than working papers which have not gone through the peer review process. In the study by O'Brien *et al*, the mean value of the small-minus-big (**SMB**) risk premium is 0.35 per cent per month, with a t-statistic of 1.12.[213] As such, the Authority notes that the SMB risk premium in this study is not significant (i.e. the difference between small and large firms is not statistically different from zero). In addition, the Authority also notes that the high-minus-low (**HML**) risk premium is not significant in 9 of 25 portfolios used in the study.

385. In addition, when both overestimates and underestimates (measured by alphas in the regressions) are taken into consideration, the Sharpe-Lintner CAPM has the mean value of alphas of -0.06 per cent, whereas the FFM has the mean value of alphas of -4.24 per cent. A lower alpha indicates that the Sharpe-Lintner CAPM produces a lower error when this model is used to price the portfolio returns.

A well accepted financial model

386. The Authority is of the view that a financial model can be called well accepted if:

- it is developed based on a theory; and
- it is widely used by practitioners.

387. The financial model is said to develop on a theory if there exists a theory in which the model uses data to test the validity of that theory. As such, a prerequisite is that a theory must exist prior to any application of the financial model. In addition, the financial model is said to be used by practitioners if it is used by different practitioners and produces a consistent outcome of the estimates when different datasets, in different periods of time are used.

388. On the above grounds, the Authority considers that the Sharpe-Lintner CAPM is a well accepted model because it was developed based on a theory (Markowitz's portfolio theory[214]) about risk and return, and it has been widely used by Australian regulators and practitioners. In contrast, the Fama-French model is based on empirical evidence. In addition, even though the Fama-French CAPM has been tied to risk factors such as liquidity (size premium) and default risk (book-to-market premium), these two factors have not gained universal acceptance.[215]

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[213] O'Brien, Michael, Tim Brailsford and Clive Gaunt, "Size and book-to-market factors in Australia", Electronic copy available at: http://ssrn.com/abstract=1206542.

[214] This theory provided the first rigorous measure of risk for investors and showed how one selects alternative assets to diversify and reduce the risk of a portfolio. It also derived a risk measure for individual securities within the context of an efficient portfolio. Based on this theory, Sharpe and several academicians extended the Markowitz's model into a general equilibrium asset pricing model that included an alternative risk measure for all risky assets (Reilly and Brown, 2006, Investment Analysis and Portfolio Management, 8th Edition, p. 229.).

[215] Koller, T.; Goedhart, M.; Wessels, D. *Valuation: Measuring and Managing the Value of Companies*, (University Edition), John Wiley & Sons, 4th Edition, 2005, p. 324.

389. In addition, the Authority notes that the 2005 Kothari, Shanken, and Sloan study[216] concludes that the FFM's statistical tests were of too low power. These authors are of the view that the economic magnitude of firm size is quite small and that the book-to-market premia could be a result of survivorship bias.[217]

390. In its recent final decision for Jemena – the New South Wales Gas Distribution network, the AER did not accept the use of FFM to derive the cost of equity.[218] Instead, the regulated business was required to use the Sharpe-Lintner CAPM to estimate the cost of equity. The AER's decision rejecting the use of the FFM to estimate the cost of equity for regulated businesses was based on the following reasons.

- There is no strong theoretical basis to support the inclusion of the additional FFM risk factors for the rate of return on equity:
  - as the model is dependent on empirical justification - that is, the systematic observance of the FFM risk premia; and
  - since the FFM risk premia are not systematically observed in the Australian market, there is no reasonable basis for the FFM to be applied in Australia.
- Evaluation of the academic literature does not support the FFM as a reliable or accurate financial model.
- Analysis from Australia, which is the relevant market for funds, shows that observed empirical evidence is not consistent with the FFM, with conflicting, variable FFM risk premia and inconsistent FFM factor coefficients. This means that it is unreasonable to conclude that the additional FFM risk factors are present in the market for funds and can be used to determine a rate of return on equity.
- In relation to evidence in other markets for funds:
  - analysis from a global perspective (including the UK, Japan and Germany) shows that the observed empirical evidence is not consistent with the FFM; and
  - analysis from the US shows conflicting evidence that does not support the FFM for each time period analysed.

391. While the FFM has achieved a degree of support in academic circles, there has also been scepticism due to concerns about 'data mining',[219] that is, the reporting of results of strong correlations between variables, without the benefit of *a priori* theory justifying the inclusion of those variables.

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[216] Kothari, S., Shanken, R., Sloan, R. (1995), "Another look at the Cross-section of expected returns", *Journal of Finance,* December 1995.

[217] Survivorship bias is the tendency for failed companies to be excluded from performance studies because they no longer exist. It often causes the results of studies to skew higher because only companies which were successful enough to survive until the end of the period are included. This is a type of selection bias.

[218] Australian Energy Regulator, 2010, Final Decision, Jemena Gas Networks: Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015, pp. 170-171.

[219] Data mining can lead to spurious correlation between variables. Data mining is the process in which the researcher will keep adding explanatory variables to a model, or adjusting the form of the model, until a statistically significant relationship is found. This process can generate spurious relationship

392. FFM has not been widely used by financial analysts and business practitioners in Australia in valuation and capital budgeting. A practical reason for this is that values of the 'theta factor' (i.e. the input factors) are not commercially available in Australia. The FFM has been applied in portfolio asset allocation in the funds management industry. There is no evidence of widespread application of the model by financial analysts and business practitioners at the individual firm level, although one example of a partial application that has been identified is the hybrid CAPM recommended by KPMG in 1993.[220]

393. The Authority considers that while the FFM continues to be considered in finance textbooks, it is used as an illustration of the potential limitations of the Sharpe-Lintner CAPM, and not because it is widely applied in business.

394. The Authority considers that the summary below from a leading corporate finance book[221] written by practitioners confirms the fact that FFM is not a well accepted model:

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

395. In conclusion, the Authority is of the view that there is insufficient evidence from both theoretical and practical grounds to confirm that the FFM is a well accepted financial model. As such, Sharpe-Lintner CAPM is used to estimate the cost of equity for Australian regulated businesses. Nevertheless, the Authority also considers the estimates of the cost of equity using the different approaches in DBP's submissions. The consideration of these estimates does not imply the validity of the models on which the estimates are derived. Rather it provides further evidence to confirm that the FFM is not a well accepted financial model on the empirical basis.

Estimates of the Cost of Equity

DBP's Proposed Revisions

396. DBP commissioned two consultants to provide advice on the estimates of the cost of equity.

- The first consultant was NERA, who estimates the cost of equity using four different versions of the CAPM and argues that they are all well accepted.
- The second consultant was SFG Consulting, who uses a brokers' research report to estimate the cost of equity and argues that these estimates are consistent with the estimates derived from CAPM models.

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between variables because one is bound, sooner or later, to find a variable that is associated with another, maybe for no other reason than accident (Melberg, H, 2000, "From spurious correlation to misleading association", the University of Oslo).

220 Lawriwsky, M., 2008, The origins of the CAPM and its application in commercial practice and economic regulation. A report to the Essential Services Commission of Victoria.

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

Estimates of the cost of equity from NERA

397. DBP commissioned NERA to estimate the rate of return on equity using four different CAPM models, as previously discussed. This study is presented under the following headings:

- assumptions, data and methodology;
- data;
- methodology; and
- results

398. Each of these themes is discussed in turn below.

Assumptions, data and methodology

399. NERA assumes a value for gamma of 0.2 for its estimates.

400. Betas are estimated for the nine regulated energy businesses that the AER used in its WACC Review in May 2009. Data is provided by Dimensional Fund Advisors Australia Ltd (**DFA**). NERA also uses an alternative data source, known as Morgan Stanley Capital International (**MSCI**), to estimate betas for the following regulated businesses:

- Alinta Limited;
- The Australian Gas Light Company;
- APA Group;
- Duet Group;
- Envestra Limited;
- GasNet Hastings Diversified Utilities Fund;
- Spark Infrastructure Group; and
- SP AusNet.

401. NERA submits that the betas of the nine regulated energy businesses were estimated using both ordinary least squares (**OLS**) and least absolute deviations (**LAD**)[222], as Henry did in his 2009 report to the AER.[223] In addition, NERA submits that estimates are computed using an equally-weighted portfolio and a value-weighted portfolio of the nine regulated energy businesses. NERA then uses the means of each set of six[224] beta estimates produced for each of the four CAPM models.

Australian financial data

402. NERA submits that, to estimate the cost of equity using all four CAPM models, the following parameters are required:

- the risk-free rate;
- the zero-beta premium;
- the betas of a comparable group of Australian regulated energy businesses; and
- the means of the three Fama-French factors.

403. NERA uses the risk-free rate of 5.51 per cent per annum that the Authority used in its Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network Submitted by Western Power.

404. For the Sharpe-Lintner CAPM and FFM, NERA uses the Market Risk Premium (**MRP**) of 6.5 per cent that it argued was used by the Authority in its Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network submitted by Western Power. This interpretation by NERA of the MRP of 6.5 per cent is mistaken. In its Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009, the Authority recommended a range for the MRP of 5 per cent to 7 per cent with the mid-point value of 6.0 per cent being adopted.

405. For the Black CAPM and the Zero-beta FFM, NERA uses a zero-beta premium of 6.50 per cent per annum and a MRP of zero per cent per annum. NERA submits that its choice is motivated by the evidence provided by Lewellen, Nagel and Shanken (2008)[225] and Lajbcygier and Wheatley (2009)[226].

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222 The method of Ordinary Least Squares (OLS) fits a line to a set of (x, y) data by choosing slope and intercept to minimise the sum of squared errors (SSE), whereas the method of Least Absolute Deviations (LAD) fits a line to a set of (x, y) data by choosing slope and intercept to minimise the sum of absolute errors (SAE). Both methods produce a line of "best fit". One of the differences between the two methods is that LAD line fitting is more robust than OLS line fitting. That is, changes in data points affect the LAD regression line less than they affect the OLS regression line.

223 Henry, Olan (2009), “Estimating Beta”, a report submitted to ACCC on 23 April 2009.

224 Estimates are computed in two ways (by OLS and LAD) and then individual security estimates are aggregated in three ways (using an equally-weighted portfolio and a value-weighted portfolio and by averaging estimates across securities). So, for each CAPM model, a set of 2 × 3 = 6 estimates is computed.

225 Lewellen, J., S. Nagel and J. Shanken, *A skeptical appraisal of asset pricing tests*, Journal of Financial Economics 96 (2010) 175-194

406. NERA submits that, using US data from 1963 to 2004, Lewellen, Nagel and Shanken's estimates are as follows:

- the zero-beta premium lies between 8.12 and 11.60 per cent per annum for the Black CAPM, and between 8.84 per cent and 11.96 per cent per annum for the zero-beta FFM; and
- the MRP lies between -1.76 and 0.40 per cent per annum for the Black CAPM and between -5.68 and -1.96 per cent per annum for the zero-beta FFM.

407. In addition, using Australian data from 1979 to 2007, Lajbcygier and Wheatley's estimates are as follows:

- the zero-beta premium is 9.96 per cent for the Black CAPM and 9.00 per cent per annum for the zero-beta version of the FFM; and
- the MRP is -2.64 per cent per annum for the Black CAPM and -1.68 per cent per annum for the zero-beta FFM.

408. As such, NERA concludes that, relative to the above estimates, determination of a zero-beta premium of 6.50 per cent per annum and a MRP of zero per cent per annum are conservative estimates.

Methodology

409. Each of the CAPM models, except for the Sharpe-Lintner CAPM, requires the estimates of risk premia (Market risk premium (MRP), HML, and SMB) and their respective betas.

410. NERA mistakenly uses the MRP of 6.5 per cent in its estimates. The means of the Fama-French HML and SMB factors are then estimated. The HML factor is the difference between the return to a portfolio of high book-to-market stocks and the return to a portfolio of low book-to-market stocks. The SMB factor is the difference between the return to a portfolio of small cap stocks[227] and the return to a portfolio of large cap stocks.

411. NERA submits that the HML premium calculated from DFA's data is economically and statistically significantly different from zero. However, the DFA SMB premium is neither economically nor statistically different from zero.

412. NERA made some adjustments to the raw data provided by DFA to estimate the HML and SMB risk premia.

- First, NERA calculated the arithmetic average of the differences between the annual returns to a portfolio of high book-to-market stocks and a portfolio of low book-to-market stocks. Similarly, NERA also calculated the arithmetic average of the differences between the annual returns to a portfolio of small cap stocks and a portfolio of large cap stocks.
- Second, these averages were adjusted to reflect an assumption that investors place a positive value on distributed franking credits.

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226 Lajbcygier P. And S. M. Wheatley, *An evaluation of some alternative models for pricing Australian stocks*, Working Paper, Monash University, 2009.

227 The small cap stocks are stocks of smaller-sized companies and the opposite is true for the large cap stocks.

413. Betas are estimated in two ways: (i) using OLS; and (ii) using LAD.

414. The individual data on nine securities for each of the nine regulated energy businesses is presented in three different ways:

- simple averages of the security beta estimates;
- an equally-weighted portfolio of the nine securities is derived, and then beta is estimated; and
- a value-weighted portfolio of the nine securities is derived, and then beta is estimated.

Results

415. NERA's estimates of the input parameters for the above four CAPM models are presented in Table 26 below.

Table 26. NERA's estimates of input parameters for four CAPM models

Model	Zero-beta premium	Beta			Risk premia		
		Market	HML	SMB	Market	HML	SMB
Sharp-Lintner CAPM		0.51			6.50		
Black CAPM	6.50	0.51			0		
Fama-French CAPM		0.57	0.41	0.28	6.50	6.12	-0.45
Fama-French CAPM (zero beta)	6.50	0.57	0.41	0.28	0	6.12	-0.45

416. Table 27 presents estimated rates of return on equity, based on the estimates of cost of equity from NERA, for the four CAPM models.[228]

Table 27. DBP's Estimated Nominal Rates of Return on Equity

Method of Determining Cost of Equity	Value (per cent)
Sharp-Lintner CAPM	8.79
Black (zero beta) CAPM	11.98
Fama-French three factor CAPM	11.57
Fama-French (zero beta) three factor CAPM	14.36

Estimates of the cost of equity from SFG Consulting

417. DBP have also commissioned the Strategic Finance Group Consulting (**SFG**) together with NERA, to provide expert advice on the issue of the estimate of the cost of equity.

228 DBNGP Revised Access Arrangement Proposal Submission, p. 20.

418. SFG has adopted two different approaches to estimate the cost of equity. First, SFG uses broker research reports produced by major broker houses, an approach known as Dividend Yield Technique. Second, a dividend discount model, or the residual income model, which was set out in a 2010 working paper by Fitzgerald et al., is used.[229]

The first approach: Dividend Yield Technique

419. SFG uses research reports from various brokers[230] to estimate the cost of equity for a sample of firms which are considered comparable to DBP, including APA Group (APA), Hastings Diversified Utilities Fund (HDF), Envestra (ENV), Spark Infrastructure (SKI), SP Ausnet (SPN), and DUET Group (DUE).

420. SFG submits that the expected return on equity available to investors has three possible components: (i) dividends; (ii) capital gains; and (iii) dividend imputation credits.

421. First, the estimates of dividends for a sample of comparable firms are considered. SFG submits that the expected dividend yield on the set of comparable firms is approximately 10.5 per cent per annum. This estimate is derived from the forecasts reported in the equity analyses from major broking houses. SFG also notes that the set of comparable firms used in its analysis is the traditional set of firms used by regulators to estimate equity beta and credit ratings. SFG states that forecasts are consistent across time (2010-2012), across firms, and across broking houses.

422. Second, the estimates of capital gains are considered. Capital gains (or price appreciations) are calculated by comparing the current stock price with the broker's 12-month price target. Capital gains vary significantly between the comparable firms, such as 1.8 per cent per year for SKI to 22.4 per cent per year for ENV.[231] SFG submits that the forecast capital gain estimates are less reliable. As such, SFG adopts a range of 0-1 per cent per year for real stock price and considers that this is conservative. SFG submits that if stock prices are assumed to increase at a real rate of 0-1 per cent per annum, and if expected inflation is 2.5 per cent per annum (a mid-point of a target band adopted by the RBA), the combined return from dividends and capital gains would be in the range of 13 to 14 per cent per year.

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229 Fitzgerald Tristan, Stephen Gray, Jason Hall and Ravi Jeyaraj, 2010 "Unconstrained estimates of the equity risk premium," Working paper, The University of Queensland, http://ssrn.com/abstract=1551748.

230 Broking houses include Macquarie Bank, UBS, Wilson HTM, Morgan Stanley, Credit Suisse, Ballieu Research, Goldman Sachs JBWere, JP Morgan, RBS Morgans, Merrill Lynch.

231 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from SFG – The required return on equity commensurate with current conditions in the market for funds, Table 3, p. 10.

423. Third, and lastly, the estimates of the benefits from dividend imputation credits are considered. SFG argues that the application of the regulatory framework only allows the regulated business to charge prices that are sufficient to generate enough earnings for the company to pay dividends and capital gains to shareholders[232] equal to $r_e \times \left[{(1-T)} \big/ {1-T \times (1-\gamma)} \right]$. As such, higher values of gamma require higher values of r_e if the regulated business is to provide its shareholders with the level of dividends and capital gains that they would expect to receive from other comparable firms. SFG then concludes that to the extent that gamma is set above zero, r_e must be set above 13 to 14 per cent.[233]

424. In its further submission in response to BHP Billiton's submission, SFG argues that this approach is simple and that it does not require any other input assumptions with significant uncertainty in their own right, as argued by BHP Billiton.[234] SFG submits that a question should be raised whether a proposed estimate of the cost of equity is commensurate with the current markets for funds.

The second approach: the residual income model

425. While acknowledging that the approach using brokers' research reports provides some advantages of being

- quite straightforward; and
- based directly on observable published forecasts from equity analysts
- SFG submits that the approach faces a short forecast horizon (three to four years for dividend yield forecasts and 12 months for capital gains forecasts). As a result, SFG submits that a more complete approach, known as the residual income model, which can be used to model dividends over a longer time horizon, is needed.

426. The residual income model, used by SFG in its submission, is as follows:

$$V_0 = BVPS_0 + \sum_{t=1}^{T} \frac{(ROE_t - r_e) \times BVPS_{t-1}}{(1+r_e)^t} + \frac{(ROE_T - r_e) \times BVPS_{T-1} \times (1+g)}{(r_e - g) \times (1+r_e)^T}$$

where:

- V_0 is the estimated value per share;
- $BVPS_0$ is the current book value per share;

232 A proportion of ${\gamma T} \big/ {1-T \times (1-\gamma)}$ of the return to equity holders (r_e) is assumed to come in the form of franking credits.

233 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from SFG – The required return on equity commensurate with current conditions in the market for funds, pp. 18-19.

234 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from SFG – The required return on equity commensurate with current conditions in the market for funds: Response to BHP Billiton submission, pp. 2-3.

- $BVPS_t = BVPS_{t-1} + EPS_t - DPS_t$ where DPS_t is estimated as the historical dividend payout ratio multiplied by EPS_t;
- r_e is the cost of equity; and
- g is the perpetual growth; T is the length of the forecast period.

427. SFG's approach is that three parameters in its model are simultaneously estimated, including a perpetual growth (g); the long-term return on book equity (ROE_T); and the cost of equity (r_e).

428. SFG has applied the above model to the set of comparable firms, as in previous approach using brokers' research reports. Two data sets are used to estimate the cost of equity: (i) analyst forecasts from the I/B/E/S/ database;[235] and (ii) brokers' research reports.

429. First, using the I/B/E/S/ data set for 12 quarters for 3 years from 2007 to 2009, SFG reports that the average implied return on equity for a set of comparable firms is 13.6 per cent. The SFG concludes that this estimate is consistent with the range of 13 to 14 per cent derived under the first approach, using brokers' research reports.

430. Second, using the brokers' research reports from 12 November 2009 to 25 February 2010, the average implied required return on equity is 14 per cent. The SFG also concludes that this estimate is consistent with the range of 13 to 14 per cent derived under the first approach, using brokers' research reports.

431. In conclusion, based on the analyses under both approaches, SFG concludes that a range of 13 to 14 per cent return on equity is appropriate when determining the allowed return on equity which is commensurate with current market conditions for funds.

432. In its further submission in response to BHP Billiton submission, SFG submits that BHP Billiton's argument that the earnings forecasts of equity analysts are optimistic on average cannot be justified.[236] SFG argues that their approach is to reconcile the future earnings forecasts of an individual analyst with the present target stock price of the same analyst and then aggregate over all analysts and all stocks in their sample. As such, SFG argues that even if an individual analyst does suffer from an optimism bias, the same bias is present in his or her forecasts and target price.

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235 The Institutional Brokers Estimate System (I/B/E/S) is a unique service which monitors the earnings estimates on companies of interest to institutional investors. The I/B/E/S database currently covers over 18,000 companies in 60 countries. It provides to a discriminating client base of 2,000 of the world's top institutional money managers. More than 850 firms contribute data to I/B/E/S, from the largest global houses to regional and local brokers, with US data back to 1976 and international data back to 1987.

236 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from SFG – The required return on equity commensurate with current conditions in the market for funds: Response to BHP Billiton submission, pp. 3-4.

Submissions

433. In its submission, Alinta expressed major concerns about DBP's proposal to use four different versions of CAPM, together with "market information", to estimate the cost of equity.[237] Key questions from Alinta are summarised as follows.

- Does the NGR permit the use of more than one financial model to derive the cost of equity?
- Are all models used by DBP well accepted?

434. In response to the first question, Alinta argued that DBP is relying on more than one financial model. Alinta argued that the NGR allows only a well accepted financial model such as the CAPM (rule 87(2)(b) of the NGR). As such, the approach adopted by DBP to estimate the cost of equity is not consistent with the requirements of the NGR. In addition, Alinta argued that the cost of equity of 13.5 per cent proposed by DBP differs to the cost of equity determined by each of the four models used by DBP to derive potential estimates of the cost of equity

435. In response to the second question, Alinta argued that the Black CAPM and FFM models are not well accepted models. This argument is based on the report by Lawriwsky for the Essential Services Commission in 2008,[238] together with the conclusions by the AER in its recent final decision for NSW Gas in June 2010.

436. BHP Billiton submitted that the first approach using dividend yields to estimate the cost of equity is problematic because such dividend yields are highly sensitive to input assumptions, many of which have significant uncertainty in their own right.[239]

437. In addition, BHP Billiton expressed its concerns on DBP's second approach to estimating the cost of equity (using dividend forecast reports).[240] BHP Billiton submitted that this approach should be disregarded for the following reasons.

- First, the estimate is overly simplistic and the use of such estimated forecasts has been demonstrated to provide unreliable results. This argument is drawn from recent academic research which demonstrates that expected return estimates from earnings and dividend-based methods are highly unreliable.[241]
- Second, reliance on analysts' estimated forecasts has been shown to be likely to result in an upwardly biased estimate. Recent academic research has found that the expected rate of return based on analysts estimates have an upward bias of around 2.5 to 3.0 per cent.[242]

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237 Alinta, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 33-38.

238 Lawriwsky, M., 2008, The origins of the CAPM and its application in commercial practice and economic regulation. A report to the Essential Services Commission of Victoria

239 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 16-17.

240 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 16-17.

241 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, p. 16.

242 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, p. 16.

- Third, DBP has provided insufficient evidence to support the input assumptions on which its estimate is based. BHP Billiton submits that the data used in dividend forecasts reports cannot be verified or properly assessed.

Considerations of the Authority

Estimates of the cost of equity by NERA

438. NERA's empirical study on the FFM uses individual stock data of the nine Australian regulated businesses. The FFM is used to adjust for business specific risks, including the firm size and the book-to-market ratio of businesses in the sample. The regulatory framework for assessment is relative to a *benchmark* exposure to risks, with the benchmark characteristics reflecting the circumstances of an efficient firm providing regulated businesses.

439. NERA's study uses the specification of the FFM in the context of the US capital market. The Authority is of the view that this specification may not represent the prevailing market conditions in estimating the rate of return for Australian regulated businesses.

440. In addition, the Authority also notes that the data used in NERA's study is not the data provided by DFA or MSCI. The data has been manipulated for the purpose of the estimates. For example, NERA has made the adjustment of returns for gearing by multiplying the return to the equity of each regulated utility by $\left(1-L_j\right)/\left(1-0.6\right)$ where L_j is the average net debt-to-value ratio over the period for which data is available for the nine regulated energy businesses to reflect the widely adopted level of gearing of 60 per cent by Australian regulators. The Authority is also of the view that it is inappropriate for all nine regulated utilities to be pooled together to estimate the HML and SMB risk premia and their betas.

441. NERA's estimates present the SMB risk premium of -0.45 for the FFM and the zero-beta FFM. This negative estimate is inconsistent with the FFM model developed from the 1993 Fama-French paper, where the size risk premium, SMB, represents the premium earned by small minus big shares. It means that the FFM states that small firms require additional returns to compensate investors for the additional risk, whereas the estimate of -0.45 from this NERA's study provides the opposite interpretation.

442. Table 28 and Table 29 below compare NERA's estimates of HML and SMB risk premia:

    - using two data sources, DFA and MSCI, in the submission to the Authority; and
    - using two NERA's studies: the 2010 study in the submission to the Authority and the 2009 study in the submission to the AER in the AER's Draft Decision, *Jemena: Access Arrangement proposal for the NSW gas networks.*

Table 28. NERA's Estimates for the FFM in Australia Using DFA and MSCI Data Sources, Weekly Data, 1 January 2002 to 31 December 2009

Data sources	Value effect			Size effect		
	Period	HML premium (%)	Statistical significance	Period	SMB premium (%)	Statistical significance
DFA	1975-2009	6.12 (2.98)	Yes	1980-2009	-0.45 (2.29)	No
MSCI	1975-2009	3.57 (2.76)	No	2001-2009	5.67 (3.81)	No

Source: NERA, 2010, Fama-French Model, 31 March 2010, p.40, p.52

Table 29. NERA's Estimates for the FFM in Australia Using DFA and MSCI Data Sources, 1975 - 2008

Data sources	Value effect			Size effect		
	Period	HML premium (%)	Statistical significance	Period	SMB premium (%)	Statistical significance
DFA	1975-2008	6.2	Yes	1980-2008	-1.2	No
MSCI	1975-2008	3.6	No	2001-2008	3.9	No

Source: AER, Draft Decision, Jemena: Access Arrangement proposal for the NSW gas networks, February 2010, Table 5.5, p.40, p.117.

443. First, the HML premium is 6.12 per cent and statistically significant based on the DFA dataset, but 3.57 per cent and not significantly different from zero based on the MSCI dataset. Similarly, the SMB premium is -0.45 per cent based on the DFA dataset, but 3.9 per cent based on the MSCI dataset, and both cases are statistically not significantly different from zero.

444. Second, while the HML risk premia of 6.12 per cent and 6.2 per cent are quite consistent in the 2010 and 2009 studies, the SMB risk premia in these two studies are significantly different: -0.45 per cent versus -1.2 per cent (using the DFA dataset) and 5.67 per cent versus 3.9 per cent (using the MSCI dataset).

445. Based on this comparison, the Authority is of the view that these estimates are best characterised as an unsystematic observance of the estimates of the Fama–French risk premium. This observance indicates a consequence of the estimates on the ground of an empirical relationship without the backing of an economic theory.

446. This view is also confirmed when the estimates of the HML and SMB risk premia from the FFM are compared across studies for the Australian capital market, as shown in Table 29.

447. Table 29 shows that the ranges of the HML risk premia, from 14.6 per cent to 6 per cent, and of SMB risk premia, from 17.2 per cent to -9 per cent, can be considered too large to confirm the presence of the risk factors when using the FFM in Australia.

448. The FFM predicts that the HML and SMB coefficients estimated from the models should be significantly different from zero. On this prediction, except for an estimate of 4.3 per cent for the SMB risk premium in the 2008 O'Brien *et al*, other estimates are significantly different from zero at the 5 per cent level of confidence.

449. In addition, the FFM also predicts that the intercept from the regression, which is the proportion of the observed return that is not explained by the FFM, should not be significantly different from zero. While there are some studies where the FFM performs well, such as Ghargori, Chan and Faff (24 out of 27 portfolios have intercepts that are not statistically significant from zero), there are studies where the FFM performs poorly, such as Ghargori, Lee and Veeraghavan (only 2 out of 12 portfolios have intercepts that are not statistically significant from zero).

Table 30. Fama-French Model in Australia

Authors	Years	Risk premia		FFM's parameter analysis		
		HML (%)	SMB (%)	Intercept not significant	HML coefficients significant	SMB coefficients significant
Fama & French, 1998[243]	1975-1995	12.3	N/A	N/A	N/A	N/A
Halliwell et al., 1999[244]	1980-1991	14.6	6.0	23 of 25	6 of 25	18 of 25
Faff, 2001[245]	1991-1999	14.0	-9.0	20 of 24	7 of 24	11 of 24
Faff, 2004[246]	1996-1999	6.0	-6.5	19 of 24	14 of 24	18 of 24
Gaunt, 2004[247]	1993-2001	8.5	10.0	19 of 25	21 of 25	13 of 28
Ghargori, Chan & Faff, 2007[248]	1996-2004	10.4	17.2	24 of 27	20 of 27	14 of 27
O'Brien et al., 2008[249]	1982-2006	9.4	4.3	14 of 25	22 of 25	16 of 25
Kassimatis, 2008[250]	1993-2005	12.6	11.5	11 of 25	20 of 25	11 of 25
Ghargori, Lee & Veeraghavan, 2009[251]	1993-2005	N/A	N/A	2 of 12	10 of 12	5 of 12

Source: AER, Draft Decision, Jemena: Access Arrangement proposal for the NSW gas networks, February 2010, Table 5.4, p.114.

243 Lajbcygier P. And S. M. Wheatley, *An evaluation of some alternative models for pricing Australian stocks*, Working Paper, Monash University, 2009.

244 J. Halliwell, R. Heaney and J. Sawicki, 'Size and book to market effects in Australian share markets: a time series analysis', *Accounting Research Journal*, 1999, vol. 12, pp. 122–137.

245 R. Faff, 'An examination of the Fama and French three-factor model using commercially available factors', *Australian Journal of Management*, 2001, vol. 26, pp. 1–17.

246 R. Faff, 'A simple test of the Fama and French model using daily data: Australian evidence', *Applied Financial Economics*, 2004, vol. 14, pp. 83–92.

247 Gaunt, 'Fama–French model: Australian evidence', *Accounting and Finance*, 2004.

248 P. Gharghori, H. Chan and R. Faff, 'Are the Fama–French factors proxying default risk?', *Australian Journal of Management*, December 2007, vol. 32(2), pp. 223–249.

249 O'Brien, Brailsford, and Gaunt, 'Market factors in Australia', Australasian Finance and Banking Conference, 2008.

250 K. Kassimatis, 'Size, book to market and momentum effects in the Australian stock market', *Australian Journal of Management*, June 2008, vol. 33(1), pp. 145–168.

251 P. Gharghori, R. Lee and M. Veeraghavan, 'Anomalies and stock returns: Australian evidence', *Accounting and Finance*, 2009, vol. 49, pp. 555–576.

450. In conclusion, the Authority does not approve the use of Black CAPM, Fama-French CAPM, and Zero-beta Fama-French CAPM to estimate the cost of equity. The Authority is of the view that Sharpe-Lintner CAPM is the only form of the CAPM that can produce a reasonable estimate for the cost of equity for regulated businesses in Australia. The Authority is also aware that the proposed cost of equity of 13.5 per cent by DBP is not directly derived from the estimates of the four CAPM models. The estimates from these four CAPM models are used to confirm DBP's position on the estimate of the cost of equity derived by SFG which uses different approaches.

Estimates of the cost of equity by SFG

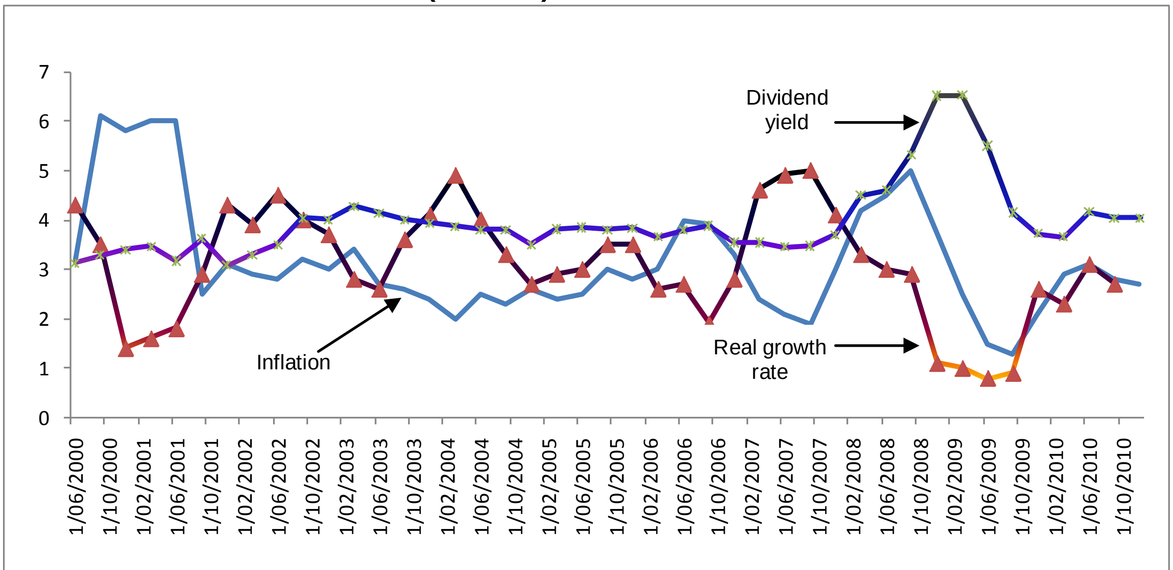
The first approach: Dividend Yield Technique

451. The Authority considers that brokers' research reports used by SFG are based on forecasts of some particular agencies for dividend yields, inflation, capital gains, and economic growth. The Authority is of the view that all series used as inputs for the brokers' forecasts exhibit a relatively high degree of volatility.

452. However, while forecasters have been reluctant to evaluate their own performances, there exists enough evidence to say that the record of economic forecasting is not encouraging.[252] Additionally, the estimate of the cost of equity using the brokers' research reports involves at least three forecasts (dividend yield, inflation and GDP growth), so the error of these estimates compounds for the estimate of the cost of equity.

453. The Authority considers recent time series of inputs for the period from June 2000 to December 2010 (data from Bloomberg).

Figure 5. Quarterly Dividend Yield, Inflation and GDP Growth, June 2000 to December 2010 (Per cent)



252 For example, see Fildes, R. and Makridakis, S. (1995). The impact of empirical accuracy studies on time series analysis and forecasting, *International Statistical Review,* 63, 3, 289-308; and Hendry, D. and Clements, M. (2003). Economic forecasting: some lessons from recent research, *Economic Modelling,* 20, 301-329.

454. Figure 5 reveals that all three series of dividend yields, inflation and GDP growth exhibit a relatively high degree of volatility. The Authority is of the view that, for any estimate, there is a degree of uncertainty involved that can be summarised in terms of a standard error: the higher the volatility, the higher the standard error. Standard deviations for dividend yield, inflation and GDP growth are 0.76, 1.18, and 1.19 respectively. A straight projection of these series is likely to be subject to large error. Therefore, some form of forecast is required.

455. SFG states, in its further submission, that:

- estimating the cost of equity for DBNGP using Dividend yields technique does not require any other input assumptions,[253] and
- even if an individual analyst does suffer from an optimism bias, the same bias is present in his or her forecasts and target price and, as such, using the earnings forecasts of equity analysts is appropriate to estimate the cost of equity for DBNGP,[254]

456. The Authority considers that these two arguments by SFG counter the fact that the approaches using the earnings forecasts, which are subjective and varied significantly across equity analysts and across times, are not fit for the regulatory purpose of estimating the cost of equity for regulated businesses.

457. Given the poor record of economic forecasting on which the brokers' research reports are based,[255] the Authority is of the view that it is inappropriate to use the brokers' research reports to derive an estimated cost of equity, particularly for a period with a high level of uncertainty.

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[253] BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 16-17.

[254] DBNGP Revised Access Arrangement Proposal Submission: Supporting document from SFG – The required return on equity commensurate with current conditions in the market for funds: Response to BHP Billiton submission, pp. 3-4.

[255] For example, see Fildes, R. and Makridakis, S. (1995). The impact of empirical accuracy studies on time series analysis and forecasting, *International Statistical Review,* 63, 3, 289-308; and Hendry, D. and Clements, M. (2003). Economic forecasting: some lessons from recent research, *Economic Modelling,* 20, 301-329. For example, Clements and Hendry derive the following nine sources of forecast error as a comprehensive decomposition of deviations between announced forecasts and realised outcomes:

- shifts in the coefficients of deterministic terms;
- shifts in the coefficients of stochastic terms;
- mis-specification of deterministic terms;
- mis-specification of stochastic terms;
- mis-estimation of the coefficients of deterministic terms;
- mis-estimation of the coefficients of stochastic terms;
- mis-measurement of the data;
- changes in the variances of the errors; and
- errors cumulating over the forecast horizon.

The second approach: the residual income model

458. The Authority notes that the residual income model used by SFG to estimate the cost of equity for DBNGP was set out in the 2010 working paper by Fitzgerald, Gray, Hall, and Jeyaraj from the University of Queensland. The Authority confirms its position that evidence from a working paper is generally given less weight than a published academic paper.

459. However, regarding the second approach used in SFG's report, the Authority notes that there are some significant issues arising from its analysis, which can be summarised as follows.

460. First, there are five comparable firms in the sample, together with 12 quarters over the three-year period. If forecasts are all available, then 60 observations (forecasts) are expected to be available for consideration. The study by SFG presents that there are only 21 forecasts (or 35 per cent of total number of expected forecasts) available for consideration. The Authority is of the view that too many missing forecasts (observations) make the analysis more difficult and its findings become less convincing.

461. Second, there are no forecasts of the cost of equity for the above set of five comparable firms for the quarters ending on 20 June 2007, 30 June 2008 and 30 September 2009. Only two forecasts are available for a set of five comparable firms for the quarters ending on 31 December 2008 and 31 December 2009.

462. Third, using I/B/E/S data, the estimated cost of equity for the set of comparable firms varies significantly across: (i) quarters; and (ii) firms. For example, for the quarter ending on 31 March 2007, only two forecasts are available for the firms APA and DUE with the cost of equity of 7.0 per cent and 16.0 per cent, respectively. These two significantly different forecasts are used to derive the average of the cost of equity for the entire set of five comparable firms of 11.5 per cent, being the average of 7.0 per cent and 16.0 per cent, for the quarter ending on 31 March 2007.

463. Fourth, some forecasts are implausible. For example, forecasts for DUE present that the cost of equity for this company is 20 per cent for the quarter ending on 30 June 2009. Three months later, the forecast cost of equity for this company decreases to 7.0 per cent, a reduction of more than 100 per cent within three months.

464. Fifth, comparing forecasts of the cost of equity for the set of five comparable firms using: (i) SFG's income residual estimates; and (ii) brokers' research reports reveals some unreliable findings.

Table 31. Estimates of the Cost of Equity

Authors	Estimates of the cost of equity (per cent per year)		
	I/B/E/S Data	Analysts' reports	Difference
APA Group	10.2	14	-3.8
DUET Group	15.3	17	-1.7
Hastings Diversified Utilities Fund	17.5	17	0.5
Spark Infrastructure	13.3	4	9.3
SP Ausnet	11.0	18	-7.0
Average of the set	13.6	14	-0.4

Source: SFG, report on Return on equity commensurate with current conditions in the market for funds, Tables 5 and 6 and ERA's analysis.

465. From Table 31, the Authority is aware that the estimates using I/B/E/S data are for the period from 1 October 2006 to 31 December 2009, whereas the estimates of the cost of capital derived from analysts' reports are for the period from 12 November 2009 to 25 February 2010. The significant difference in these two estimates for the same company such as APA Group and Spark Infrastructure raise a concern of the precisions of these estimates. For example, the estimates of the cost of equity for Spark Infrastructure are 13.3 per cent per year, using I/B/E/S data, and only 4 per cent per year, using analysts' reports – a difference of 9.3 per cent in these two estimates. The Authority notes that this significant difference results in the unreliable estimates of these approaches in estimating the cost of equity. As such, in the interest of providing certainty, the Authority is of the view that these approaches should be assigned less weight in the Authority's decision on the cost of equity.

466. The Authority notes that, even though DBP and one of its consultants on the issue, NERA, present lengthy discussions on different versions of CAPM, namely the Black CAPM, the FFM CAPM and the zero-beta FFM CAPM, DBP has effectively ignored the results of all four versions of CAPM and expressed its preferences for adopting the estimate of the cost of equity based on dividend yield forecasts prepared by SFG.

467. In conclusion, the Authority does not approve the use of brokers' research reports and the residual income model as proposed by SFG to estimate the cost of equity for DBNGP. The Authority is of the view that DBP and its consultants, NERA and SFG, do not provide any new or convincing evidence to depart from the widely adopted method, the Sharpe-Lintner CAPM, used by Australian regulators to estimate the cost of equity for regulated businesses in Australia.

Authority's Decision

468. On the basis of the above analyses of the three alternatives to the Sharpe-Lintner CAPM, the Authority is of the view that the Sharp-Lintner CAPM is the most widely used CAPM model to estimate the cost of equity. The Authority is not aware of any regulators in Australia who use different versions of the CAPM to estimate the cost of equity for their decisions.

469. In the CAPM, the equity beta value is a scaling factor applied to the market risk premium to reflect the relative risk to equity funds in the particular firm or activity in question.

470. The Authority considers that in ascribing a value to the equity beta, primary reliance should be placed on capital market evidence and statistical estimates of beta values, where these are available for comparable businesses.

471. In its 2009 WACC review for electricity transmission and distribution network service providers, with the assistance of Associate Professor Henry of the University of Melbourne, the AER established a sample of Australian businesses, comprising gas-only network businesses, one electricity-only network business, network businesses active in both electricity and gas, and general utility businesses. Given the limitations of available Australian data, the AER considered that gas network businesses could be considered as reasonable but not perfect comparators to electricity network businesses, given that both industries involve the transportation of energy.[256]

472. The AER considers that the reasonable range of the equity beta for a gas or electricity distribution network of between 0.4 and 0.7 is justified on the grounds of empirical information. The AER has also considered the need for regulatory certainty and adopting a conservative approach in estimating the equity beta, commensurate with prevailing market conditions and the risks involved in providing reference services. On this basis, the AER considers that a value of 0.8 provides the best estimate of the equity beta arrived at on a reasonable basis for gas and electricity transmission and distribution networks.[257]

473. There are a substantial number of regulatory determinations for electricity and gas networks in Australia that have applied equity beta values of 1.0 and less than 1.0.[258] Empirical studies of beta values have been subject to scrutiny and debate as part of regulatory processes. Over the past five years, there has been a downward trend in the beta values being applied in regulatory decisions for gas and electricity businesses.

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[256] The main sample consisted of: AGL (2002 to 2005); Alinta (2002 and 2007); Alinta Network Holdings Pty Ltd (2003 to 2006); Country Energy (2002 to 2006); Diversified Utility and Energy Trusts (2003 to 2008); ElectraNet Pty Ltd (2002 to 2008); Energy Australia (2002 to 2006); Envestra Ltd (2002 to 2008); Ergon Energy Corporation (2002 to 2008); ETSA Utilities (2002 to 2008); GasNet Australia (Operations) Pty Ltd (2002 to 2007); Integral Energy (2002 to 2006); SP AusNet Group (2006 to 2008), and SPI PowerNet Pty Ltd (2002 to 2005).

[257] See for example: Australian Energy Regulator 2009-10, Final decision: WACC review, May 2009; Jemena: Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015 (Draft Decision February 2010).

[258] Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 183.

474. A summary of previously adopted values of equity beta by regulators in Australia is shown in Table 32. Historically, equity betas have been set higher for regulated gas and electricity transmission businesses, compared to distribution businesses. This reflects the historical risk profiles of transmission versus distribution networks (which have a diversified customer base and more stable demand).

Table 32. Equity Beta in Gas Transmission and Distribution Determinations

Regulator (Year)	Sector	Equity Beta (Final Decision)
ERA (2005, Final) [259]	Gas transmission	0.8-1.33
QCA (2006, Final) [260]	Gas transmission	1.0
ACCC (2006, Final) [261]	Gas transmission	1.0
ESC (2008, Final)[262]	Gas distribution	0.8[263]
AER (2009, Draft) [264]	Gas distribution	0.8
ERA (2010, Final) [265]	Gas transmission	0.8-1.0
AER (2010, Final) [266]	Gas distribution	0.8
AER (2010, Final) [267]	Gas distribution	0.8

259 Economic Regulation Authority, May 2005. Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline.

260 ACCC, December 2006. Final Decision: Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline.

261 ACCC, December 2003. East Australian Pipeline Limited: Access Arrangement for the Moomba to Sydney Pipeline System.

262 ICRC, October 2004. Review of access arrangement for ActewAGL natural gas system in ACT, Queenbeyan and Yarrowlumla, Final decision, p. 174-177.

263 The ESC selected an equity beta value of 0.7, and then effectively adjusted the beta to 0.8 by making a transitional allowance. Essential Services Commission Appeal Panel, Decision on the Envestra Albury Appeal: E2/2008.

264 ICRC, October 2004. Review of access arrangement for ActewAGL natural gas system in ACT, Queenbeyan and Yarrowlumla, Final decision, p. 174-177.

265 Economic Regulation Authority, April 2010. Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline.

266 Australian Energy Regulator, 2010, Final Decision, Country Energy Wagga Wagga Natural Gas Distribution Network, Access arrangement, July 2010-June 2015, p. 45; and Access Arrangement proposal: ACT, Queanbeyan and Palerang gas distribution network, p. 68.

267 Australian Energy Regulator, 2010, Final Decision, Jemena Gas Networks: Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015.

475. In the 2009 review of WACC parameters, the AER concluded that a beta value of 0.8 is appropriate for both transmission and distribution businesses in the National Electricity Market.[268] In the most recent determinations for gas networks, the AER has consistently applied an equity beta value of 0.8.[269] The AER noted that:

> Although reliance on market data suggests a value of between 0.4 and 0.7, the AER concludes that a conservative approach has merit, ensuring that the efficient network service provider has opportunity to at least recover efficient costs.[270]

476. In general, volume risk arises for gas networks because gas is used for specific purposes (e.g. electricity generation, heating) and therefore demand volumes will be impacted by weather trends that may deviate substantially from average expectations. Contractual arrangements such as long term take-or-pay contracts mitigate this risk. The AER recently noted that while it accepts that gas businesses may have greater volume risk (compared to an electricity business), the degree to which volume risk represents business specific risk or systematic (market wide) risk has not yet been settled.[271]

477. The AER has published three final decisions on access arrangement proposals for gas networks: the NSW gas networks, ActewAGL and Country Energy.[272] The equity beta value determined in all three decisions was 0.8. In the AER decision on the NSW gas networks, the AER noted that:

> The nature of the gas industry (including the regulatory regime) means that the equity beta of a benchmark efficient service provider is likely to be significantly less than the beta of the market portfolio. This is because demand for energy is relatively inelastic, and the nature of regulated price and revenue caps further reduces fluctuation in income (page 175).

478. The Authority adopted the range of equity beta of 0.8 and 1.0 in its Final Decision on the proposed access arrangement for Goldfields Gas Pipeline in May 2010 and a point estimate of equity beta of 0.8 in its most recent Draft Decision on the proposed access arrangement for Western Australia Gas Networks.

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268 Australian Energy Regulator, May 2009. Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution), p. 6.

269 Australian Energy Regulator 2009-10. Jemena: Access arrangement proposal for the NSW gas networks
1 July 2010 – 30 June 2015, (Draft Decision February 2010). ActewAGL: Access Arrangement for the ACT Gas distribution network, (Draft Decision November 2009); and Country Energy Wagga Wagga Natural Gas Distribution Network, Access arrangement, July 2010-June 2015,(Draft Decision November 2009)

270 Australian Energy Regulator, 2010, Final Decision, Access Arrangement proposal: ACT, Queanbeyan and Palerang gas distribution network, p. 68.

271 Australian Energy Regulator, February 2010. Jemena: Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015; p.129 (Draft Decision February 2010.

272 Australian Energy Regulator, 2009-10. Jemena: Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015, (Final Decision June 2010). ActewAGL: Access Arrangement for the ACT Gas distribution network, (Final Decision March 2010). Country Energy Wagga Wagga Natural Gas Distribution Network, Access arrangement, July 2010-June 2015, (Final Decision March 2010).

479. Therefore, the Authority considers that a reasonable point estimate for equity beta is 0.8, at a gearing level of 60 per cent debt to total assets.

480. The Authority does not agree with DBP that other versions of CAPM, namely the Black CAPM, the Fama-French CAPM, and the zero-beta Fama French CAPM, are well accepted models.

481. The Authority does not approve the approach of using dividend forecast reports to estimate the cost of equity.

482. The Authority does not approve DBP's proposal in relation to the equity beta. The Authority considers that a reasonable point estimate for equity beta is 0.8, using the Sharpe-Lintner CAPM, at a gearing level of 60 per cent debt to assets.

Cost of Debt

DBP's Proposed Revisions

483. DBP has estimated a nominal pre-tax return on debt as the sum of three components:[273]

- the nominal risk free rate;
- a debt risk premium; and
- an allowance for debt raising costs.

484. DBP submits that a substantial part of its existing debt finance must be refinanced in 2010 and 2011 and AMP Capital Investor (**AMP**) was engaged to advise the Operator on possible options for refinancing.

Notational Credit Rating

485. DBP states that pricing data for its estimated return on debt assumes a borrower with a credit rating in the BBB range, and not with a specific credit rating of BBB+. DBP also submits that a major Australian gas pipeline business in the APA Group is currently rated BBB. DBP submits that its current credit rating is BBB-.

The nominal risk free rate

486. DBP is of the view that the reference rate for the pricing of debt by lenders is not the nominal risk free rate, but the Bank Bill Swap Rate (**BBSW**)[274] for a tenor of 10 years, reported by Bloomberg. DBP also submits that the BBSW for the average of 20-trading days to 18 March 2010 is 6.06 per cent.

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273 DBNGP Revised Access Arrangement Proposal Submission, page 21.

274 The Australian Financial Markets Association (AFMA)'s bank-bill reference rate is published daily. BBSW is the Australian equivalent of London Inter Bank Offered Rate (LIBOR) or Singapore Inter Bank Offered Rate (SIBOR), etc. The purpose of BBSW is to provide independent and transparent reference rates for the pricing and revaluation of Australian Dollar derivatives and securities (AFMA, available at www.afmadata.com.au and ANZ's Financial Dictionary: The language of money).

A debt risk premium

487. DBP argues that with a large regulated utility (in the order of $3 billion), it is expected that at least some funds might be sourced from international capital markets. DBP, based on the advice of AMP, submits that the most appropriate domestic and international markets in which funds might be sourced are as follows:[275]

- Australian bank market, including 5-years and 7-years tenor;
- Australian bond market, including 5-years and 7-years tenor;
- US public bond (144a) market[276] for 10-years tenor; and
- US private placement market[277] for 10-years tenor.

An allowance for debt raising costs

488. AMP submits that debt risk premiums are only one part of the cost of debt. AMP contends that a borrower's cost of debt will also be impacted by a number of other cost factors, including: underwriter fees; upfront fees; other transaction costs; cross currency swap; credit margin on AUD swaps; and borrower's advisor fees. The range of these other cost factors is from 44 bps to 65 bps per year, depending on the market in which the funds are sourced. For example, the total other cost factors are 44 bps when debt finance is sourced from the 7-year Australian bond market, whereas they are 63 bps when debt is sourced from both the 10-year US public bond market and the 10-year US private placement market, and 65 bps when debt is sourced from the 5-year Australian bank market.

Total cost of debt: Debt risk premium and debt raising cost

489. AMP submits a list of factors which need to be taken into account in accessing the appropriate mix of portfolio debt funding, including:[278] price of debt; tenor mix, execution certainty (the deal being executed when required), funding diversity (a mix of funding markets and investor base to reduce single market risk), flexibility, and market nuances (name, sector, rating restrictions).

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275 AMP provides a discussion on other international capital markets, including Asian Bank Market; Eurobond market; and Sterling market, and concludes these markets are not suitable to borrow funds for large regulated utilities.

276 The US public market (144a) is the world's largest and most liquid capital market. Under Rule 144A, large, sophisticated qualified financial institutions can trade unregistered debt securities with each other, without regard to restrictions that would otherwise apply (e.g. compliance with US GAAP (Generally Accepted Accounting Principles in the United States)). The rule, while intended to increase capital raising opportunities for all firms, was particularly targeted toward international firms for which the cost of complying with US disclosure standards was seen to be restrictive (DBNGP Revised Access Arrangement Proposal Submission: Supporting document from AMP, p. 6.)

277 A US private placement note is an unregistered debt security marketed and sold to Accredited Investors, a definition that includes most institutional investors as well as sophisticated individual investors with significant net worth. US insurance companies tend to be the dominant purchasers of private placements, and take a much longer term view of credit (to match duration of assets) (DBNGP Revised Access Arrangement Proposal Submission: Supporting document from AMP, p. 6.)

278 DBNGP Revised Access Arrangement Proposal Submission: Supporting document from AMP, p. 10.

490. With the assumed regulated asset base of $A3.5 billion, together with a gearing level of 60 per cent, DBP's total debt requirement is A$2.1 billion. AMP proposes the following allocations:

Table 33. AMP's Estimates of Debt Risk Premium

Markets	Allocation		Cost of Debt (Per cent)
	Per cent	A$ (million)	
Australian Bank Market (5 years)	28.6	600	9.71
Australian Bank Market (7 years)	9.5	200	10.71
Australian Bond Market (5 years)	0	0	8.92
Australian Bond Market (7 years)	9.5	200	9.15
US Public Market – 144a (10 years)	33.3	700	9.74
US Private Placement Market (10 years)	19	400	9.79
Total Debt Portfolio	**100**	**2,100**	**9.73**

Source: AMP Capital Investor, page 10.

491. On the basis of the calculations shown in Table 33 by AMP, DBP proposes that the total cost of debt is 9.73 per cent per year.

Submissions

492. In its submission, BHP Billiton expressed its concern that the proposed cost of debt of 9.73 per cent is too high.[279] BHP Billiton submits that the well accepted approach to estimating the cost of debt, as the sum of nominal risk free rate and debt risk premium, should be used.

493. Public submissions in response to the Authority's Discussion Paper on the bond-yield approach to estimate the debt risk premium will be discussed in later sections.

Considerations of the Authority

494. The debt margin (also referred to as the debt premium) is a margin above the risk free rate reflecting the risk in provision of debt finance to the regulated activity.

Notational Credit Rating

495. The Authority notes that the credit rating of BBB+ has been consistently adopted in all decisions by the AER for gas distribution over eastern Australia. This credit rating of BBB+ was adopted in the 2009 WACC Review by the AER for electricity transmission and distribution network service providers.

[279] BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 28-30.

496. The Authority observes that, in the 2009 WACC Review, the AER noted a strong precedent for the use of a BBB+ credit rating for energy businesses, not electricity businesses alone, among Australian regulators. The AER has also conducted its analysis to conclude that the credit rating of BBB+ is appropriate, using the median credit ratings[280] and the "best comparators" approaches[281] for the sample of companies including electricity and gas transmission and distribution businesses. In addition, the AER is of the view that electricity networks are close comparators to the benchmark efficient gas network service providers. As a result, the AER has adopted a credit rating of BBB+ in all its decisions for both electricity and gas regulated businesses after its 2009 WACC Review.

497. In addition, the Authority agrees with the AER that the benchmark gas distribution service provider operates in a regulated environment that includes a number of features common to the electricity service providers, which were considered in the AER's 2009 WACC Review. These features effectively reduce these service providers' exposure to risks relative to an unregulated competitive business:

- the mechanism allows for the annual adjustment for inflation. This results in a lower exposure to inflation risk for service providers;
- the mechanism allows for certain costs to be passed on to consumers during the access arrangement period. This also results in a lower exposure to costs which are not forecasted at the commencement of the access arrangement period proposed by the service providers; and
- the mechanism allows a service provider to submit an access arrangement variation proposal for the Authority's approval.

498. Based on all the above considerations, the Authority does not agree with DBP's submission that gas businesses are riskier compared with regulated electricity businesses and that gas businesses in Western Australia are riskier than those operating in different areas of Australia. As such, the Authority is of the view that an appropriate credit rating for the DBP is BBB+. This credit rating of BBB+ is consistent with the Authority's recent Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010, the recent Final Decision on Proposed Revisions to the Access Arrangement for the Western Australian Gas Networks in Febryary 2011, and with all recent decisions on gas networks by the AER.

Proxy for the risk free rate

499. The DBP proposes to use a BBSW as the proxy for the risk free rate. The Authority notes that DBP does not provide any evidence regarding its proposal to depart from the use of the 10-year Commonwealth Government Securities (CGS) as the proxy for the risk free rate.

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280 The AER observed a range of credit ratings from BBB+ to A- among the sample of energy businesses considered and concluded that the median approach suggests that the credit rating for a benchmark efficient network service provider may be A- (AER's WACC Review, p. 284). Also, the AER considered that ElectraNet, with the credit rating of BBB+, is the most appropriate "best comparator" business (AER's WACC Review, p. 386).

281 Australian Energy Regulator, May 2009, Final Decision, Review of the weighted average cost of capital parameters for electricity transmission and distribution network service providers, pp. 385-386.

500. The Authority notes that, in the AER's WACC Review in 2009, the BBSW was proposed as the alternative proxy for the 10-year CGS by the Competition Economists Group (**CEG**). However, the CEG has since withdrawn this proposal on the basis that it is unreliable. The Authority agrees with the AER's view that this decision by the CEG indicates the lack of persuasive evidence for moving away from the 10-year CGS yield as the proxy for the risk free rate and, indeed, the inherent risk of doing so.

501. In addition, the Authority also notes, during the AER's WACC Review in 2009, there were proposals to depart from the use of the 10-year CGS as the proxy for the risk free rate by using either:[282]

- yields on Commonwealth government guaranteed bank debt;
- yields on State government debt; or
- the current implied breakeven inflation rate as implied by the Fisher's equation.

502. First, the Australian Government Guarantee Scheme for Large Deposits and Wholesale Funding (the **Guarantee Scheme**) was announced by the Government on 12 October 2008 and formally commenced on 28 November 2008.[283] The arrangements were designed to promote financial system stability in Australia, by supporting confidence and assisting eligible authorised deposit-taking institutions (**ADIs**) to continue to access funding at a time of considerable turbulence. They were also designed to ensure that Australian institutions were not placed at a disadvantage compared to their international competitors that could access similar government guarantees on bank debt. However, this Guarantee Scheme has been closed from 31 March 2010, due to the improvement in funding conditions and the recent or imminent closure of guarantee schemes in a number of other countries. The Authority is of the view that the Commonwealth government guaranteed bank debt is not entirely free from the risk of default, particularly when the Guarantee Scheme is closed. As such, it could not represent a reliable alternative proxy for the risk-free rate.

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282 Australian Energy Regulator, May 2009, Final Decision, Review of the weighted average cost of capital parameters for electricity transmission and distribution network service providers, pp. 136-140.

283 Australian Government, Guarantee Scheme for Large Deposits and Wholesale Funding, available at http://www.guaranteescheme.gov.au/, accessed on 7th July 2010.

503. Second, the Authority has considered the relevance of State government debt as a reliable alternative proxy for the risk-free rate. The Authority agrees that there exists a liquidity premium[284] between the CGS and State government debt. However, it is argued that a premium should be paid for CGS due to their relatively higher liquidity characteristics in comparison with State government debt, which is considered to be relatively illiquid. It is not clear whether the CGS yield is downwardly biased, or the State Government debt yield is upwardly biased.[285] In addition, the State of Queensland was downgraded to AA+ from AAA credit rating, which suggests that State Government debt is not entirely free from the risk of default. As such, it could not represent a reliable alternative proxy for the risk-free rate.

504. Third, the Authority has considered the current breakeven inflation rate as implied by Fisher's equation. Fisher's equation[286] estimates the relationship between the nominal interest rate and real interest rate in the presence of inflation. It defines the nominal interest rate (i) as the sum of real interest rate (r) and expected inflation (π). Nominal and indexed CGS yields have been inversely correlated, in the context of the RBA's inflation forecasts. However, the Authority agrees with the AER's view that the yields on indexed CGS are not a reliable estimate given supply concerns in that market. The indexed CGS market is characterised by illiquidity.[287] As such, the Authority is of the view that it could not represent a reliable alternative proxy for the risk-free rate.

505. The Authority is also aware that Associate Professor Handley, the AER's consultant on the issue of risk free rate for its WACC Review in May 2009, argued that the purpose for which the risk free rate is to be used is an important consideration that should be taken into account in determining an appropriate proxy for the risk free rate. In this regard, a risk free rate implied from a "fixed-income derivative market" is clearly relevant for derivative pricing purposes, but not necessarily relevant for corporate cost of capital purposes. He then concluded that there is insufficient evidence to justify any claim that the observed CGS yield is an inappropriate proxy for the risk free rate used in the CAPM.[288]

506. In conclusion, based on the considerations above, together with the fact that DBP does not provide any evidence in support of its proposal to use the BBSW as the proxy for the risk free rate, the Authority is of the view that there is not sufficient evidence to depart from the use of the Commonwealth Government Securities as the proxy for the risk free rate in the CAPM. This decision is consistent with all Australian regulatory decisions.

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284 This is a premium that investors will demand when any given security cannot be easily converted into cash. When the liquidity premium is high, then the asset is said to be illiquid, which will cause prices to fall.

285 Australian Energy Regulator, May 2009, Final Decision, Review of the weighted average cost of capital parameters for electricity transmission and distribution network service providers, p. 137.

286 A more accurate equation can be seen as: $(1+i)=(1+r)\times(1+\pi)$.

287 Australian Energy Regulator, May 2009, Final Decision, Review of the weighted average cost of capital parameters for electricity transmission and distribution network service providers, p. 138.

288 Handley, J. 2008, Comments on the CEG Report: "Establishing a proxy for the risk free rate". A report prepared for the Australian Energy Regulator.

An estimate of the nominal risk free rate

507. The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth government bond is widely used as a proxy for the risk free rate in Australia.[289] CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. The Authority's consideration of the appropriate estimate of the nominal risk free rate is provided in paragraphs 687 to 714.

508. For the purpose of this Draft Decision, the Authority calculates a nominal risk free rate of 5.46 per cent for the 20 day trading period till 28 February 2011.

509. The Authority notes that these values will need to be updated at the time of the Final Decision, so as to be commensurate with prevailing market conditions at the time.

Debt Risk Premium

510. The Authority considers that DBP, and its consultant AMP, do not provide any convincing evidence for different allocation of debt into different markets. This allocation is very arbitrary and the cost of debt will be significantly different when the allocation changes.

511. The Authority does not agree with DBP's proposal that the Authority should assume that debt is raised from both Australian and US capital markets, because the size of debt is very large. DBP argues that most of its debts will be retired largely in 2011. DBP submits that this amount could not be solely sourced from the Australian capital market. The Authority is of the view that the principle of using a benchmark firm for the purpose of estimating the rate of return for regulated businesses needs to be applied. As such, the Authority considers that it is the regulated business' responsibility to phase out the amount borrowed in each period to minimise its borrowing risks. As a result, the argument from DBP cannot be justified.

512. In addition, were the debt risk premium to be estimated using data from the US capital market, for consistency, all other WACC parameters such as nominal risk free rate, MRP and inflation would also need to be derived using US data. This is contrary to current practices applied by Australian regulators. Also, under the NGL and the NGR, the market for funds is meant as the Australian financial market. As such, the Authority is of the view that borrowing must be treated as sourced from the Australian capital market, using Australian data.

513. The Authority's preferred method for estimating a debt risk premium is the use of market evidence of debt costs for businesses with a credit risk profile consistent with a BBB+ credit rating, at the end of October 2010, with relevant sources of market evidence including CBASpectrum and Bloomberg. An allowance for debt issuance costs of 12.5 basis points is added.

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289 Although Blanco *et al* consider swap rates as superior to Government bonds as a proxy for the risk free rate and state that "it is well known that government bonds are no longer an ideal proxy for the unobservable risk free rate". See Blanco, Brennan, and Marsh, "An Empirical Analysis of the Dynamic Relation between Investment-Grade Bonds and Credit Default Swaps", *The Journal Of Finance*, Vol. LX, no. 5 October 2005, p. 2261, for details.

A new method to estimate the Debt Risk Premium

514. In its previous decisions, the Authority relied on the estimates of 10-year fair yield curves derived by Bloomberg and CBASpectrum. However, Bloomberg has in recent times progressively shortened its estimates of fair yields across credit ratings for Australian corporate bonds. Additionally, in September 2010, CBASpectrum ceased publishing its estimates of the fair yield curves across all credit ratings for Australian corporate bonds.

515. It is noted that the Authority's method for estimating the debt risk premium, as well as the nominal risk free rate, has in the past assumed the borrowing term is 10 years. A 10-year term has been consistently adopted by all Australian regulators in the energy sector since the Australian Competition Tribunal's (**Tribunal**) 2003 GasNet decision.[290]

516. There have also been recent developments in the Australian regulatory environment regarding the approach to estimating the debt risk premium.

- The Australian Competition Tribunal's decision in the ActewAGL appeal in September 2010.
- The AER's Final Decision on the Victorian electricity Distribution Network Service Providers (**DNSPs**) in October 2010.
- The IPART's Discussion Paper on "Developing the approach to estimating the debt margin" in November 2010.

The Estimates of Bloomberg's Fair Yield Curves

517. Australian regulators have historically had regard to Bloomberg's estimates of fair yield curves to estimate the debt risk premium for their regulatory decisions. Prior to the Global Financial Crisis, which started in 2008, an estimate of the fair yield curve for 10-year BBB Australian corporate bonds was consistent with observed yields for Australian corporate bonds (of the same rating) trading in the market at that time. This consistency is illustrated in Figure 6 below using estimates of the fair yield curve for 10-year BBB Australian corporate bonds from 10 November 2005 to 9 October 2007.

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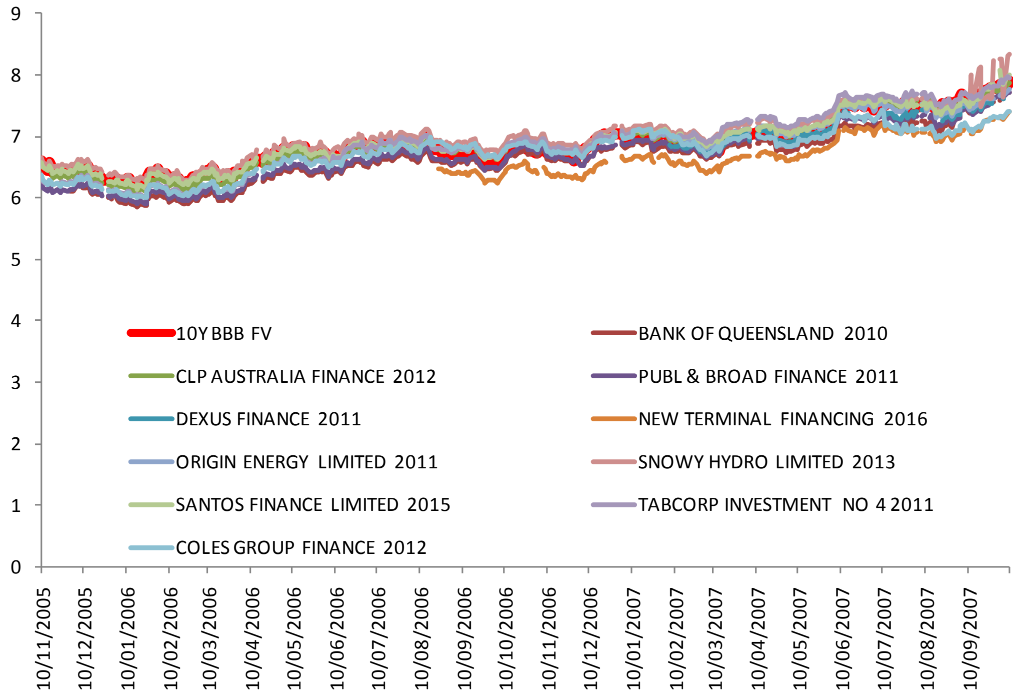
290 Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6*, 23 December 2003, paragraph 48, p. 18.

Figure 6. Bloomberg's 10-year BBB Fair Yield Curve and Observed yields for BBB/BBB+ Australian corporate bonds, 10 November 2005 – 9 October 2007 (Per cent)



Source: Bloomberg

518. Since the cessation of Bloomberg's estimate of the 10-year BBB fair yield curve on 9 October 2007, some Australian regulators, including the Authority and the AER, have extrapolated to a 10-year term from Bloomberg's estimate of the 8-year BBB fair yield curve. The extrapolation was based on the assumption that the yield spreads between 10Y A and 8Y A is equal to that of 10Y BBB and 8Y BBB:

$$10\text{Y BBB} = 8\text{Y BBB} + (10\text{Y A} - 8\text{Y A})$$

519. The above extrapolation was not possible after 18 August 2009 when Bloomberg ceased providing estimates of the 8-year BBB fair yield curve, and 10-year and 8-year A fair yield curves.

520. The Authority, as well as the AER, then analysed the appropriateness of using other fair yield curves from Bloomberg to extrapolate to a 10-year BBB fair yield curve. Both regulators came to the conclusion that the difference between the 10-year and 7-year AAA fair yields should be added to the 7-year BBB fair yield to gain an estimate of the 10-year BBB fair yield.

$$10\text{Y BBB} = 7\text{Y BBB} + (10\text{Y AAA} - 7\text{Y AAA})$$

521. However, on 22 June 2010 Bloomberg again shortened its estimates of fair yield curves for Australian corporate bonds by ceasing to publish its estimates for both 10-year and 7-year AAA fair yield curves.

522. The duration of Bloomberg's fair yield curves are now well below the 10-year time period which Australian regulators have traditionally used for setting the debt risk premium and risk free rate.

523. It is understood that Bloomberg is currently deriving estimates of the fair yield curves for the credit ratings and terms to maturity shown in Table 34 below. Bloomberg estimates the fair yield curves for 5-year terms across all credit ratings. For the credit ratings of A and BBB, Bloomberg also estimates the fair yield curves for 7-year terms to maturity, although there are no estimates for 6-year fair yield curves.

Table 34. List of fair yield curves from Bloomberg as at 18 November 2010

	Credit rating	Maturity (M=Month; Y=Year)
1	AUD Australia AAA[291]	3M, 6M, 1Y, 2Y, 3Y, 4Y, and 5Y
2	AUD Australia AA[292]	3M, 6M, 1Y, 2Y, 3Y, 4Y, and 5Y
3	AUD Australia A[293]	3M, 6M, 1Y, 2Y, 3Y, 4Y, 5Y, and 7Y
4	AUD Australia BBB[294]	3M, 6M, 1Y, 2Y, 3Y, 4Y, 5Y, and 7Y

Source: Bloomberg

524. A major concern is that, since the bond market is thinner[295] than in the past, Bloomberg's estimate of the 7-year BBB fair yield curve is substantially different from the observed bond yields in the Australian bond market, as illustrated in Figure 7 below. This illustration is for the period when data on yield for the 7-year BBB is most recently available - after the cessation of the Bloomberg's estimate of 8-year BBB on 18 August 2009 until the end of October 2010. Since the method used by Bloomberg to derive its fair yield curves is not released to the public, the Authority is unable to understand and verify this difference.

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291 Bloomberg ceased publishing its estimates of the fair yield curves for AAA 7Y, 8Y, 9Y, 10Y, and 15Y on 22 June 2010; and for AAA 20Y on the 30 June 2005.

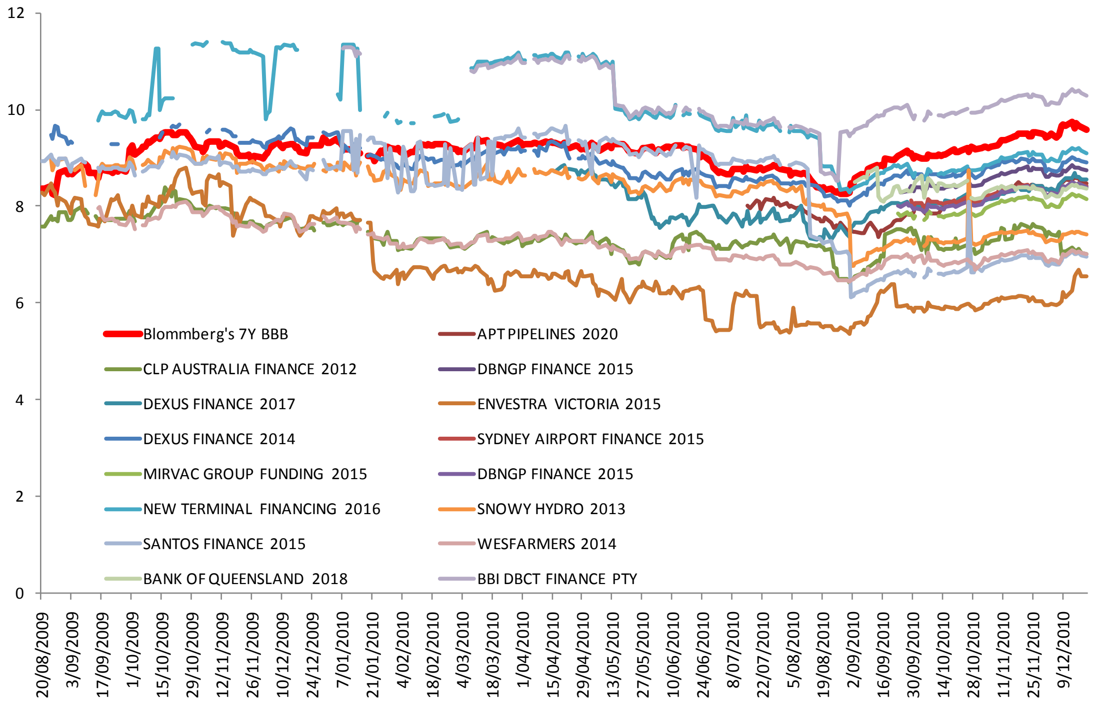
292 Bloomberg ceased publishing its estimates of the fair yield curves for AA 7Y on 18 August 2009; and for AA 8Y on 19 June 2006.

293 Bloomberg ceased publishing its estimates of the fair yield curves for A 8Y, 9Y, and 10Y on 18 August 2009.

294 Bloomberg ceased publishing its estimates of the fair yield curves for BBB 8Y on 18 August 2009; for BBB 9Y, and 10Y on 9 October 2007; and for BBB 15Y on 14 March 2002.

295 This means that the volumes traded in the market are lower than desirable for the derivation of average values.

Figure 7. Bloomberg's 7-year BBB Fair Yield Curve and Observed yields for BBB/BBB+ Australian corporate bonds, 19 August 2009 – 31 October 2010 (Per cent)



Source: Bloomberg

The Australian Competition Tribunal's Decision on the ActewAGL Matter in 2010

525. Regulators have historically used a 10-year term for estimation of the debt risk premium. However, the Authority notes that the ACT, in its recent decision for the ActewAGL gas network in September 2010, commented that:

> "The reason a 10 year bond was originally chosen was because, in the past, many firms favoured long term debt, albeit that it came at a higher cost, because it reduced refinancing or roll-over risks. The high rate was then hedged via interest rate swaps. That may no longer be the position. If not, the AER may need to reconsider its approach in light of more current strategies of firms in the relevant regulated industry. Further, **there seems to be little point in attempting to estimate the yield on a bond which is not commonly issued**" [emphasis added].[296]

[296] Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT 4*, 17 September 2010.

526. The Authority notes that current bond market conditions are significantly different from those in the past. The Australian bond market is very illiquid for long-term bonds with terms to maturity of 5 years and above, with insufficient numbers of bonds traded in the market to generate reliable industry-wide estimates. This is the reason why CBASpectrum decided to cease publishing its estimates of the fair yield curves for Australian corporate bonds.[297] Similarly, Bloomberg has shortened the duration of bonds in which their fair yield curves are derived across different credit ratings.

The AER's Method

527. In its recent Final Decision on the Victorian electricity distribution businesses in October 2010,[298] the AER adopted a new approach to estimating the debt risk premium. In this approach, the debt risk premium is derived as the weighted average of the Australian Pipeline Trust (**APT**) bond, which is assigned a 25 per cent weight, and an extrapolation of the Bloomberg 7-year BBB fair yield curve to 10-years, which is assigned a 75 per cent weight. The Bloomberg 7-year BBB fair yield curve is extrapolated to a 10-year BBB fair yield curve using the spread between 10-year AAA and 7-year AAA Australian corporate bonds in June 2010 – the last month Bloomberg produced these two AAA fair yield curves. The rationale for the AER's new approach is summarised below.

528. First, the AER considered the APT bond (APT is the financing arm of APA Group, a gas transmission and distribution network service provider). This 10-year BBB rated bond was issued by the APT in July 2010. The AER is of the view that, prima facie, the APT bond represents a useful benchmark corporate bond rate because it reflects a 10-year maturity, and provides an acceptable proxy for the BBB+ credit rating. The AER considered that the nature of the investments and markets by the APA Group provide a close match to those of electricity network service providers.

529. Second, the AER considered the reliability of independent estimates of fair yields by Bloomberg, together with the uncertainty surrounding the APT bond as a single observation. The AER is of the view that it is appropriate to use the yields derived from the Bloomberg 7-year BBB fair yield and the spread between the 10-year and 7-year AAA fair yields to extrapolate to a 10-year term. The AER considered that this 10-year fair yield estimate should be used together with the APT bond, to estimate the debt risk premium for its Final Decision on Victorian electricity DNSPs.

297 In its announcement, CBASpectrum states that: "Sparse and heterogenic data have always made it difficult to produce a broad range of reliable credit curves in Australia. CBASpectrum has sought to overcome this problem in the past through the use of a number of econometric variables and assumptions that take account of additional information such as implied default rates, sector composition, historical relativities and spread performance of other rating bands. However, disparity of the data has increased and many of these relationships have changed over the past few years, meaning that reliability of the models designed to indicate where various credits should trade has receded. Users have also tended to confuse these fair value estimates with alternative models estimating where generic credit curves have actually traded and used the data for purposes other than relative value analysis".

298 Australian Energy Regulator, October 2010, Victorian electricity distribution network service providers: Distribution determination 2011 – 2015, pp. 472-584.

530. Third, the AER was of the view that more weight should be given to Bloomberg's fair yield curve than the APT bond. The AER considered that Bloomberg accurately represents yields on shorter rated BBB bonds (e.g. 7 years). On the other hand, the yield on the APT bond reflects a directly observed yield for one specific 10-year BBB bond, notwithstanding that it may be reflective of the efficient cost of debt for regulated network service providers. Accordingly, the AER considered that a 75 per cent weighting for Bloomberg and a 25 per cent weighting for APT is appropriate to reflect a reasonable and practical approach in setting the debt risk premium.

531. It should be noted that the 10-year and 7-year AAA fair yields are no longer provided by Bloomberg. The Authority notes the AER's recently revised approach in its Final Decision on Victorian electricity DNSPs, relying on the use of 10-year and 7-year AAA fair yield curves (which are no longer available), will be increasingly unrelated to the prevailing conditions in the market for funds.

IPART's Proposed Method

532. IPART recently released its discussion paper seeking comments from stakeholders on its proposed method to estimate the debt margin (or debt risk premium). Three key points from IPART's paper are summarised below:

- the data source;
- the statistical approach; and
- the term to maturity.

533. In considering the data source, IPART is of the view that the Australian and US bond markets appear to be the most appropriate markets to access when making its regulatory decisions. In addition, IPART suggests that the Bloomberg fair yield curves may be suitable if used together with other data sources.

534. When discussing its statistical approach IPART is of the view that using the median of the sample of bonds tends to be more appropriate than using upper, lower and midpoint values, which was its previous approach.

535. In determining the appropriate term to maturity, IPART indicated that it is considering shortening the term to maturity of bonds which are used to derive the debt risk premium, from 10 years to the term that matches the regulatory period.

536. IPART has not yet decided on the method to be used to calculate the debt risk premium for its future regulatory decisions. However, the above three factors appear to be the most important considerations for IPART.

The Authority's Intended Approach: A Bond Yield Approach

537. After careful consideration of the Tribunal's decision on the ActewAGL matter in September 2010, the AER's Final Decision on Victorian electricity DNSPs in October 2010, and IPART's discussion paper on debt margin in November 2010, the Authority considers that:

- extrapolation to a 10-year term based on estimates of the fair yield curves available from Bloomberg is problematic because it could add significant inaccuracy in and inconsistency across regulatory decisions;

- the lack of observable bonds with terms to maturity of 10 years warrants a broader sample of bonds with varying terms for deriving the debt risk premium; and
- the 10-year BBB APT bond is a relevant benchmark but should not be the only benchmark in determining a debt risk premium commensurate with the prevailing conditions in the market for funds and the risks involved in providing reference services.

538. In the Discussion Paper, the Authority proposed to discontinue the previous practice of basing the debt risk premium on a 10-year corporate bond using Bloomberg's extrapolated data but rather to base the debt risk premium on a sample of bond yields of varying terms to maturity.

539. The Authority favours the use of the bond-yield approach, which relies on bond yields observed directly from the Australian financial market. The Authority is not persuaded that bond markets in other countries should be used to inform this analysis. The Authority has consistently used data from the Australian financial market to estimate the WACC parameters. As such, foreign investors are only recognised to the extent that they invest in the domestic market. This means that the weighting given to foreign investors should be based on their domestic level of wealth and not on their global level of wealth. Under this framework, the aggregate amount of wealth is that amount invested in the domestic market portfolio. Wealth invested outside of the domestic market is outside the model and, as such, plays no role in the pricing of domestic assets.[299]

540. Australian financial data has been consistently used by Australian regulators to estimate the debt risk premium as well as other WACC parameters. The Authority does not intend to depart from this current practice.[300]

Consistency versus Market Relevance

541. Given the current condition of the Australian bond market, the Authority notes that most Australian corporate bonds currently traded in the market have a maturity term well below 10 years. The Authority has considered the trade-off between:

- consistency between the debt risk premium and other WACC parameters, such as the nominal risk free rate and expected inflation, in terms of a 10-year term; and
- how well the estimates of the debt risk premium are commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services ("market relevance").

542. The Authority is of the view that the market relevance of the estimates of the debt risk premium should carry more weight than the requirement of consistency with other WACC parameters. The reasons for this are twofold.

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299 Handley, J. April 2009, *Further comments on the valuation of imputation credits,* Report prepared for the AER, 15 April 2009, p. 17.

300 The Authority is aware that, in its recent Draft Decision on the approach to estimate the debt risk premium, IPART included bonds, issued by Australian companies in the US market, denominated in American dollars, in the sample of bonds to derive the debt risk premium for its regulated businesses.

543. First, attempting to maintain consistency with other WACC parameters is likely to have reduced the level of market relevance, and this relevance is likely to be further compromised in the future.

544. In this regard, there is an inherent instability in the process of extrapolating from Bloomberg's 7-year BBB to the 10-year BBB fair yield curve. The current approach by the AER is to use the spread between the 10-year AAA and 7-year AAA fair yields. It is noted that Bloomberg ceased publishing fair yield curves for both 10-year AAA and 7-year AAA fair yield curves on 22 June 2010. Additionally, the use of 10-year and 7-year AAA fair yield curves for Australian corporate bonds will become increasingly outdated if used for future regulatory decisions. In the current financial environment, the Authority considers that it is possible that Bloomberg will continue to shorten its estimates of fair yield curves. As such, errors from the extrapolation approach may become even larger in the future.

545. Second, moving away from the 10-year term provides for a larger sample of Australian corporate bonds to be considered, which should improve the estimate of the debt risk premium. This is because any measure that relies on a small sample of data points will be less reliable than one based on a larger sample.

546. This view is further supported by the fact that individual Australian corporate bonds are often not traded daily in the Australian financial market. The daily bond prices provided by Bloomberg do not necessarily reflect executed trades in the market on the day. For some days when there are not enough trades in the market, the daily bond pricing from Bloomberg is only an approximate market value of the bond.

547. As such, a large sample of data will provide a more reliable estimate of the debt risk premium for a benchmark firm. This is also consistent with the Tribunal's view, in its decision for the ActewAGL gas network in September 2010, that the current market does not have sufficient numbers of long term bonds to determine fair yields.[301]

548. In summary, the Authority considers that there are good reasons to depart from the 10-year term adopted in previous regulatory decisions on the debt risk premium:

- First, there is a significant deviation between Bloomberg's estimate of the 7-year BBB fair yield curve and observed yields from Australian corporate bonds traded in the financial market;
- Second, Bloomberg's estimation of 10-year and 7-year AAA fair yield curves for Australian corporate bonds ceased in June 2010. The use of 10-year and 7-year AAA fair yield curves for the Australian corporate bonds will become increasingly outdated if used for future regulatory decisions.
- Third, Bloomberg has progressively shortened its estimates of the fair yield curves across credit ratings for Australian corporate bonds. The Authority considers that it is likely that Bloomberg will again shorten its estimates of fair yield curves in the future. Using the 7-year BBB fair yield curve in deriving the debt risk premium is problematic because this approach is subject to uncertain data being available from Bloomberg.

[301] Australian Competition Tribunal, *Application by ActewAGL Distribution [2010] ACompT 4*, 17 September 2010, paragraph 72.

- Fourth, Bloomberg's method to estimate the fair yield curves is not disclosed to the public. As such, its estimates cannot be replicated. Using estimates of Bloomberg's estimates of fair yield curves lacks transparency.
- Fifth, CBASpectrum has recently decided to cease publishing its estimates of fair yield curves for Australian corporate bonds across all credit ratings.

549. The Authority has given consideration to the term of the nominal risk free rate in paragraphs 687 to 715 and to the term of expected inflation in paragraphs 718 to 725.

The Establishment of a Benchmark Sample of Australian Corporate Bonds

550. The Authority is of the view that each bond included in the sample of Australian corporate bonds used to derive the debt risk premium for regulated businesses should ideally satisfy three criteria. The security should ideally:

- Criterion 1: have the same Standard and Poor's credit rating as the regulated businesses (BBB/BBB+ in this case because a credit rating of BBB+ is generally adopted by regulators for regulated businesses).
- The Authority considers that it is currently appropriate to include all Australian corporate bonds within the BBB band credit rating in the sample. This also reflects a conservative approach taken by the Authority in selecting the bonds in the sample. The Authority is aware that Bloomberg has used all BBB-/BBB/BBB+ corporate bonds, known as "BBB band", to estimate the fair yield curve for the so-called BBB fair yield curve. As such, bonds with a credit rating of BBB- are also included in the sample of the bonds. However, the inclusion of bonds with a credit rating BBB-, were available, would need to be subject to review over time.
- Criterion 2: be in the same industry (the regulated utility sector); and
- Criterion 3: have a maturity of two years or longer to ensure that there are sufficient bonds in the sample for the analysis. This criterion has been used by the AER and IPART.

551. It would be ideal to derive a sample of Australian corporate bonds that meet all three of the desirable criteria above. However, given the current state of the Australian bond market, practical (i.e. less restrictive) criteria are necessary to select a sample of the Australian corporate bonds to estimate the debt risk premium.

552. In particular, the Authority notes that there are only four bonds issued by the Australian energy sector which are currently traded in the financial market. The Authority examined the actual term of debt portfolios of the energy businesses as shown in Table 35 below.

Table 35 List of Australian corporate bonds issued by the energy sector in February 2011[302]

Name of business	S&P Credit rating	Maturity	Years to maturity as at 28 February 2011
APT	BBB	22 July 2022	9.59
Santos	BBB+	23 Sep 2015	4.76
Envestra Victoria	BBB-	14 Oct 2015	4.82
DBNGP	BBB-	29 Sep 2015	4.78
Sample average years to maturity			5.78

Source: Bloomberg and Economic Regulation Authority's analysis

553. The lack of liquidity in the market for corporate bonds, particularly for bonds approaching 10 year terms, suggests that the method of estimating the debt risk premium using a 10-year term is increasingly problematic.

554. Accordingly, the Authority proposes to adopt the following approach to determine the sample of Australian corporate bonds to be used to estimate the debt risk premium, using the "search" function from Bloomberg:

- credit rating of BBB-/BBB/BBB+ by Standard & Poor's;
- time to maturity of 2 years or longer;
- bonds issued in Australia by Australian entities and denominated in Australian dollars;
- inclusion of both fixed bonds[303] and floating bonds;[304] and
- inclusion of both Bullet and Callable/ Putable redemptions.[305]

302 In a current sample of Australian corporate bonds as at 28 February 2011, only four bonds were issued by the energy sector. However, the inclusion of Santos bond in the regulated energy sector is questionable.

303 This is a long term bond that pays a fixed rate of interest (a coupon rate) over its life.

304 This is a bond whose interest payment fluctuates in step with the market interest rates, or some other external measure. Price of floating rate bonds remains relatively stable because neither a capital gain nor capital loss occurs as market interest rates go up or down. Technically, the coupons are linked to the bank bill swap rate (BBSW) (it could also be linked to another index, such as LIBOR), but this is highly correlated with the RBA's cash rate. As such, as interest rates rise, the bondholders in floaters will be compensated with a higher coupon rate.

305 A callable (putable) bond includes a provision in a bond contract that give the issuer (the bondholder) the right to redeem the bonds under specified terms prior to the normal maturity date. This is in contrast to a standard bond that is not able to be redeemed prior to maturity. A callable (putable) bond therefore has a higher (lower) yield relative to a standard bond, since there is a possibility that the bond will be redeemed by the issuer (bondholder) if market interest rates fall (rise).

555. The Authority notes that bonds issued by individual companies change over time, as does the credit rating of the company. As a result, the sample of the Australian corporate bonds will be updated for future regulatory decisions. In addition, it is noted that only bonds in the sample which are currently traded (i.e. data on fair yields available from Bloomberg) in the averaging period are included in the sample of bonds used to derive the debt risk premium.

A Method to Estimate the Debt Risk Premium from a Benchmark Sample of Australian Corporate Bonds

556. Since bonds in the sample exhibit different characteristics, such as different industries and different terms until maturity, consideration needs to be given as to whether weights should be applied to each bond to reflect their relative importance in the sample. The weighting approaches that could be adopted are:

- a simple average (or equally weighted average);
- a "number-of-years-until-maturity" approach (in which bonds with more years to maturity are given greater weight than bonds with fewer years to maturity);
- an "amount-issued" approach (where more weight is given to bonds issued in greater amounts); and
- an approach where the median[306] of a sample is used. For a sample with an odd number of observations, the median value is the value of the single middle observation from the sample. If there is an even number of observations in the sample, then the median is calculated as the average of the two middle values.

557. The weighted average of yields (WAY) is defined as:

$$\mathrm{WAY} = \sum_{i=1}^{n} w_i \overline{Y}_i;$$

where:

- n is the number of bonds in the sample;
- w_i is the weight assigned to bond i in the sample $\left(w_i = {K_i}/{K} \right)$;
- K and K_i are the total value issued (or years to maturity) and value issued (or years to maturity) of each bond, respectively, to which the weight for each bond is calculated; and
- $\overline{Y}_i$ is the average of the fair yields for bond i in the averaging period.

306 The median of a sample of observations is the numeric value which separates the higher half of a sample from the lower half when observations from the sample are arranged from the lowest value to the highest value.

Table 36. BBB-/BBB/BBB+ Australian Corporate Bonds, February 2011

No.	Name of business	Bloomberg ticker	Coupon	Maturity	Main industry
1.	APT PIPELINES	E1325336 Corp	7.75	22/07/2020	Electric transmission[307]
2.	BANK OF QUEENSLAND LTD	EH390789 Corp	10.75	4/06/2018	Commercial Banks Non-US
3.	NEXUS AUSTRALIA	EI204253 Corp	3.6	31/08/2017	Special Purpose entity
4.	NEXUS AUSTRALIA	EI204261 Corp	3.6	31/08/2019	Special Purpose entity
5.	DBNGP FINANCE CO PTY	EI414656 Corp	8.25	29/09/2015	Gas transportation
6.	DEXUS FINANCE	EI223256 Corp	8.75	21/04/2017	Mortgage
7.	ENVESTRA VICTORIA PTY LTD	EC866427 Corp	6.25	14/10/2015	Gas distribution
8.	LEIGHTON FINANCE	EH911249 Corp	9.5	28/07/2014	Diversified financial service
9.	SYDNEY AIRPORT FINANCE	EI308853 Corp	8	6/07/2015	Finance-Other Services
10.	MIRVAC GROUP FUNDING LTD	EI195249 Corp	8.25	15/03/2015	Real Estate Oper/Development
11.	MIRVAC GROUP FINANCE LTD	EI414696 Corp	8	16/09/2016	Real Estate Oper/Development
12.	NEW TERMINAL FIN	EF641357 Corp	6.25	20/09/2016	Special Purpose entity
13.	BBI DBCT FINANCE PTY	EF461870 Corp	6.25	9/06/2016	Diversified Financial Services
14.	SANTOS FINANCE	EF102609 Corp	6.25	23/09/2015	Oil Comp-Exploration & Production
15.	WESFARMERS LTD	EH964875 Corp	8.25	11/09/2014	Retail-Misc/Diversified
16.	WESFARMERS LTD	EH964867 Corp	7.68	11/09/2014	Retail-Misc/Diversified

Source: Bloomberg

307 This is a classification from Bloomberg. APT pipelines are generally classified as a business in a gas industry.

558. Given that the current market for bonds in Australia is relatively thin for the period until 28 February 2011, as presented in Table 36 above, the Authority makes the following observations:

- When the credit rating of BBB-/BBB/BBB+ is targeted, 16 bonds satisfy Criterion 1 (the same credit rating) and Criterion 3 (maturity of two years and longer), but not Criterion 2 (the same industry as the regulated business).
- When the industry-based criterion is targeted, together with Criterion 3, only a few bonds are found (e.g. APT Pipelines and Santos).

559. Based on the above analyses, and to provide a broad sample, the Authority considers that it is appropriate to include all bonds which satisfy Criteria 1 and 3 in the sample of bonds.

Public Submissions in response to the Authority's Discussion Paper on Debt Risk Premium

560. In response to the Authority's Discussion Paper on Debt Risk Premium, 13 public submissions were received from the following organisations:

- Verve Energy;
- DBP;
- Western Australia Gas Networks (WAGN);
- Goldfields Gas Transmission (GGT);
- Western Power;
- BHP Billiton;
- Brookfield;
- WestNet Rail;
- Australian Rail Track Corporation (ARTC);
- Horizon Power;
- Alinta Gas;
- Water Corporation; and
- Western Australian Council of Social Service (WACOSS).

561. Key issues raised in these public submissions are discussed below.

Selection criteria: which bonds should or should not be included in the benchmark sample?

562. In its submission, Verve Energy suggested that the Authority should monitor the inclusion of BBB- Australian corporate bonds in the benchmark sample of bonds to derive the debt risk premium. Verve Energy suggested this is to ensure that the goal of widening the capture of referable corporate debts does not change the average rating of the included businesses from BBB/BBB+. Verve Energy submitted the inclusion of BBB- bonds is likely to increase the resulting debt risk premium, inappropriately advantaging the regulated business.[308] Verve Energy also submitted that the Authority may wish to estimate the premium included in callable bonds and make adjustment from their yields when those callable bonds are included in the benchmark sample.[309]

563. In a similar manner, BHP Billiton submitted that the inclusion of BBB and BBB- bonds does not reflect the recognised credit ratings of regulated assets and so could be expected to result in an upwardly biased estimate of the debt risk premium for regulated businesses. BHP Billiton considered that such bonds with credit ratings of BBB and BBB- should be excluded from a benchmark sample of bonds to derive the debt risk premium for regulated businesses. BHP Billiton suggested excluding callable bonds from the benchmark sample because these bonds could be expected to trade at higher yields than those without a callable redemption.[310]

564. Western Power and its consultant, KPMG, submitted that bonds issued by financial institutions should be removed from the benchmark sample because they have materially different capital structures to non-financial institutions. Western Power also proposed that putable bonds, hybrid securities, subordinated bonds should also be excluded from the benchmark sample.[311]

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308 Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 1.

309 Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 2.

310 BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p. 6.

311 Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, pp. 18-20.

Selection criteria: cut-off point

565. Western Power and its consultant, KPMG, submitted that Australian infrastructure businesses tend to have a preference for, and tend to use, longer dated funding raised both in Australia (over the past 6 months) and offshore (over the past 12 months). Therefore, they argued that bond pricing observations of less than 5 years are irrelevant when determining the cost of debt for a benchmark business.[312] KPMG proposed that the Authority considers varying the criteria for the bonds included in the Authority's benchmark sample by increasing the minimum term to maturity to 5 years.[313] KPMG argued that Australian infrastructure businesses such as Toll, Asciano, AGL, Energy Gas Partnerships, United Energy Distribution, Electranet and Envestra have all sourced 5-17 year funding from offshore US markets and this is indicative of the preference for, and use of, longer dated funding.[314]

566. In its submission, Alinta was of the view that the absence of Australian corporate bonds with a longer term to maturity (excluding the APT bond) might be taken to indicate that the Authority's benchmark sample of corporate bonds with term to maturity less than 5 years is likely to better reflect the prevailing market conditions in the market for funds.[315] However, Alinta was cautious that this approach may inadequately compensate investors. As such, Alinta proposed that the benchmark sample should exclude all corporate bonds with less-than-5-year term to maturity.[316]

567. DBP, in its submission, argued that market realities, together with the requirements of the NGR, dictate a move away from the "10 years to maturity" assumption.[317]

The proposed four weighting approaches

568. Verve Energy expressed its concern that the Authority's adoption of a conservative weighting approach, which produces the highest value of debt risk premium, would be in favour of the regulated businesses. Verve Energy proposed the Authority adopt the most neutral position in considering the weighting approach adopted.[318]

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312 Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 2.

313 Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 14.

314 Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 15.

315 Alinta, *Measuring Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 3.

316 Alinta, *Measuring Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 4.

317 DBP, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 14.

318 Verve Energy, *Estimating Debt Risk Premium*, submission in response to the Authority's Discussion Paper on Debt Risk Premium, January 2011, p. 2.

569. BHP Billiton submitted that adopting the highest outcome of the proposed four approaches would be inconsistent with the requirement of the NGL. BHP Billiton proposed the selection of the most appropriate approach should be made by detailed reviews of all aspects of each approach, and not purely on taking a conservative approach.[319]

Illiquidity of bonds in the Authority's benchmark sample

570. In its submission, Australian Rail Track Corporation (**ARTC**) submitted that Bloomberg may not be including certain BBB bonds in the sample it uses to construct its fair value curves if the bonds are not well priced (i.e. illiquid). The ARCT also submitted that the Authority has not considered why certain bonds in its benchmark sample are not referenced in Bloomberg's sample.[320] Brookfield expressed its similar concern – the lack of liquidity in the corporate bond market.[321]

571. Goldfields Gas Transmission (**GGT**), and its consultant Synergies Economic Consulting (**Synergies**), submitted that the Authority does not consider the liquidity characteristics of the bonds in its benchmark sample. Synergies argued that Bloomberg only includes liquid bonds to produce a reliable estimation of the fair value curves and that, to be well-priced, the bond must be liquid to ensure that the price is reliable.[322]

572. GGT and Synergies also submitted that the APT bond was excluded by Bloomberg in the sample used to construct its estimate of fair value curves as at 31 December 2010. The reason for this exclusion was that the price of the APT bond is an indicative price and due to a lack of liquidity in the bond, the price is not considered to be a reliable price.[323]

573. Horizon Power and its consultant, Economic Insight, submitted that if bonds issued by a regulated entity are illiquid, then an illiquidity premium should be allowed in the cost of debt. In addition, they were of the view that an illiquidity premium needs to be derived separately and it is not useful to calculate an average of the debt risk premium based on a mix of liquid and illiquid bonds.[324]

[319] BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p. 7.

[320] Australian Rail Track Corporation, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, pp. 3-4.

[321] Brookfield, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 3.

[322] GGT, and Synergies' supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p. 11.

[323] GGT, and Synergies' supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p. 16.

[324] Horizon Power and Economic Insight's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 8.

Inconsistency of "terms to maturity"

574. Western Australian Gas Networks (**WAGN**) expressed its concern that it is unclear about the way in which the nominal risk free rate is to be determined. WAGN submitted that there is obvious inconsistency in that the debt risk premium is obtained as the difference between the weighted average yields of bonds, which is less-than-10-year term to maturity, and the nominal risk free rate over the same sampling period, which is 10-year term to maturity.[325]

575. Western Power and its consultant, KPMG, argued that there is an inconsistency issue with regard to terms to maturity. They submitted that subtracting a shorter dated security from a longer dated base/risk free rate is expected to systematically understate the DRP, possibly by a material amount, depending on the shape of the underlying yield curve.[326]

Retrospective analysis

576. BHP Billiton submits that a retrospective analysis should be undertaken using historical data that compares the results from the Authority's intended approach with that from Bloomberg's estimate of the fair value curve for the same period of time with the purpose of providing insights into any deficiencies or biases of the intended approach.[327]

Authority consideration

577. For ease of the discussion, the Authority considers, in turn, each of the above issues raised in the public submissions in response to the Authority's Discussion Paper on Debt Risk Premium in December 2010.

Selection criteria: which bonds should or should not be included in the benchmark sample?

578. The Authority agrees that inclusion of BBB and BBB- Australian corporate bonds in the benchmark sample used to derive the debt risk premium should be closely monitored. The benchmark credit rating for regulated businesses is generally BBB+, therefore inclusion of BBB- and BBB bonds may overestimate the debt risk premium. However, given that the Australian bond market is currently very thin, the Authority is of the view that inclusion of all credit rating bonds within the BBB band is warranted to ensure there are sufficient bonds available for the benchmark sample.[328]

325 Western Australian Gas Networks, response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, p. 8.

326 Western Power, and KPMG's supporting document, submission in response to the ERA's Discussion Paper on Debt Risk Premium, 7th January 2011, p. 15.

327 BHP Billiton Nickel West, submission in response to the ERA's Discussion Paper on Debt Risk Premium, January 2011, pp. 4-5.

328 The Authority is aware that Bloomberg used a BBB-band of Australian corporate bonds to estimate its fair yields curve for BBB bonds. This implies that both BBB and BBB- bonds are included in the Bloomberg sample. However, the Authority notes that there are currently no BBB- bonds included in the Bloomberg sample for February 2011.

579. In addition, the Authority is of the view that using a large, heterogeneous source of data is likely to provide a more reliable estimate of the debt risk premium. A sample size of the data is also used to determine the confidence level of an estimate.

580. The Authority also notes that the AER has used a sample of Australian corporate bonds with terms to maturity of less than 10 years to test whether estimates of fair yield curves from Bloomberg or CBASpectrum fit better with observed yields of the bonds in the sample.

581. The Authority is aware of the limitations of including bonds from different industries, of less than 10 years term to maturity and with callable/putable redemption in the benchmark sample. However, as previously discussed, the Authority is of the view that a large sample of bonds will likely result in a better estimate of the debt risk premium which is then applied to regulated businesses. In addition, the key strengths for the bond yield approach are its “market relevance”, simplicity, and transparency. As a result, putting too many constraints on the selection criteria will add unnecessary and arguable complexities into the approach.

Selection criteria: cut-off point

582. Given the very thin Australian bond market at the present time, the cut-off of terms to maturity of 2 years for individual bonds to be included in the sample seems reasonable to ensure that there are enough bonds included in the benchmark sample. Other Australian regulators including the AER and IPART used the cut-off of 2 year terms to maturity in their previous decisions as noted above. The average term to maturity of the 16 bonds in the benchmark sample is 5.43 years even though the cut-off term is 2 years.

The proposed four weighting approaches

583. The Authority notes that Verve Energy and BHP Billiton argue that adopting the highest estimate of the debt risk premium among four weighting approaches would be in favour of the regulated businesses. The Authority is of the view that it is appropriate to assume that bonds with longer terms to maturity should be given greater weight than bonds with shorter terms to maturity to derive a weighted average for the benchmark sample. This view is also consistent with the finance principle: a risk and return trade-off in that longer term investment should be compensated by a higher return. As a result, the Authority considers that a weighted average approach using the term to maturity of the bonds should be used.

Illiquidity of bonds in the benchmark sample

584. The Authority is aware that some of the bonds included in the benchmark sample used in the Authority’s bond yield approach are not referenced by Bloomberg to construct its fair value curves.

Table 37. BBB-/BBB/BBB+ Australian Corporate Bonds used by Bloomberg and by the Authority, February 2011

No.	Bonds only in the Sample used by the ERA's Bond Yield Approach	Bonds in common in both samples	Bonds only in the Sample used by Bloomberg's Fair Yield Approach
1.	APT PIPELINES LTD (2020)	LEIGHTON FINANCE LTD	PUBL & BROAD FINANCE LTD (2011)
2.	BANK OF QUEENSLAND LTD (2018)	WESFARMERS LTD	ENERGY PARTNERSHIP GAS (2011)
3.	NEXUS AUSTRALIA MGT (2017)	MIRVAC GROUP FUNDING LTD	TRANSURBAN FINANCE CMPNY (2011)
4.	NEXUS AUSTRALIA MGT (2019)	NEW TERMINAL FINANCING	ORIGIN ENERGY LIMITED (2011)
5.	DEXUS FINANCE PTY LTD (2017	SANTOS FINANCE LIMITED	TABCORP INVESTMENT NO 4 (2011)
6.	ENVESTRA VICTORIA PTY LT (2015)	DBNGP FINANCE CO PTY	CLP AUSTRALIA FINANCE (2012)
7.	SYDNEY AIRPORT FINANCE (2015)	BBI DBCT FINANCE PTY	COLES GROUP FINANCE (2012)
8.		MIRVAC GROUP FINANCE LTD	HOLCIM FINANCE AUSTRALIA (2012)
9.			TRANSURBAN FINANCE CO PT (2014)
10.			SNOWY HYDRO LIMITED (2013)

Source: Bloomberg and Authority's analysis

585. The Authority notes that 10 bonds used by Bloomberg to construct its estimates of the fair value curves are not included in the Authority's benchmark sample. Out of these 10 bonds, 8 bonds are excluded because they have terms to maturity of less than the "minimum of 2 years term to maturity" criteria stated in the Authority's bond yield approach. The two bonds issued by Transurban Finance were not included in the Authority's benchmark sample to estimate the DRP. The main reason for this is that this company is assigned with a credit rating of A- by S&P.

586. The Authority notes that bond prices from Bloomberg's data terminal can be categorised into three different groups:

- Indicative prices
- Executable prices
- Traded prices

587. Indicative prices account for nearly 90 per cent of the bond prices available on the Bloomberg bond database. Since market makers have no obligation to execute trades at indicative prices, it is not unusual to find indicative prices being very different to actual market prices.[329]

588. Executable prices are available only for bonds traded on some electronic trading platforms. However, most electronic trading platforms only offer executable prices to non-competitors and the subscription costs of accessing executable prices could be very expensive.

589. The Authority also notes that around 10,000 out of 510,000 bonds on Bloomberg database currently have Composite Bloomberg Bond Trader (**CBBT**) prices, which are Bloomberg Generic (**BGN**) prices based on executable prices.[330]

590. The Authority is aware that only bonds with BGN are included in the sample of bonds that is used in the Bloomberg estimates of the fair value curves. BGN price is the simple average price of all kinds of prices, including indicative prices and executable prices, quoted by Bloomberg's price contributors over a specified time window. Bloomberg also states that the availability of the BGN price for a bond is an indication of good liquidity for that bond and in some cases, bond prices from a specific pricing source are used in lieu of BGN prices (e.g. fixing prices).

591. The Authority notes that 10 out of 16 bonds have BGN pricing data in the Authority's benchmark sample of Australian corporate bonds for the period until 28 February 2011. The six bonds that do not have BGN pricing data for the period considered include bonds issued by APT (mature in 2020); Nexus Australia (2017); Nexus Australia (2019); Dexus Finance (2017); Envestra Victoria (2015); and Wesfarmers (2014 Floating bond).

592. The Authority notes that, when the option of "CBBT Only" (i.e. include liquid bonds only) is selected from Bloomberg' search, together with all selection criteria stated in the Discussion Paper on Debt Risk Premium, only one bond issued by Mirvac Group Finance (2016) has CBBT pricing data. This bond is included in the Authority's benchmark sample of Australian corporate bonds to estimate the DRP.

593. As the Australian corporate bond market is very thin and illiquid at the moment the Authority is of the view that indicative prices are the best estimates of the market values of bond prices.

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329 Lee, M. (2007), *Bloomberg Fair Value Market Curves,* presentation at International Bond Market Conference 2007, Taipei, available at www.taipeibond.gretai.org.tw, accessed on 21 November 2010 or search from www.google.com.au

330 Lee, M. (2007), *Bloomberg Fair Value Market Curves,* presentation at International Bond Market Conference 2007, Taipei, available at www.taipeibond.gretai.org.tw, accessed on 21 November 2010 or search from www.google.com.au

Inconsistency of "terms to maturity"

594. The Authority agrees that there is an inconsistency when the debt risk premium is calculated as the difference between bond yields with less-than-10-year terms to maturity and the 10-year CGS as a risk free rate. As such, the Authority has decided to adjust the 10-year Commonwealth Government Securities (**CGS**) rates to be consistent with the term to maturity for each of the 16 bonds in the benchmark sample.

595. As presented in paragraph 714, the Authority considers that the estimated nominal risk free rate of return should be 5.46 per cent, for the period until 28 February 2011. This nominal risk free rate is estimated from the 5-year CGS bonds. The same principle is applied to estimate the risk free rate for Australian corporate bonds with more-than-5-year terms to maturity.

596. For example, column (5) from Table 38 shows that the nominal risk free rate for the APT bond with 9.39 years to maturity is estimated to be 5.695 per cent for the period till 28 February 2011.[331] The nominal risk free rate for the APT bond, which is used to estimate the debt risk premium for this bond, is higher than the risk free rate for 5-year CGS bonds.

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[331] The estimated risk free rate for each bond in the benchmark sample is determined using two different CGS bonds that have maturity dates closely matched with the actual maturity date of the relevant bond.

Table 38 Observed Yields, adjusted Nominal Risk Free Rates, and Debt Risk Premium for BBB-/BBB/BBB+ Australian Corporate Bonds, for the period to 28 February 2011 (Per cent)

No.	Bond	Term to maturity as at 28 February 2011 (years)	Observed yields (per cent)	Risk Free Rate (per cent)	Debt Risk Premium (per cent)
1	APT PIPELINES LTD	9.39	8.487	5.695	2.792
2	BANK OF QUEENSLAND LTD	7.26	8.536	5.642	2.893
3	NEXUS AUSTRALIA MGT	6.50	9.494	5.597	3.896
4	NEXUS AUSTRALIA MGT	8.50	9.666	5.671	3.994
5	DBNGP FINANCE CO PTY	4.58	8.718	5.420	3.297
6	DEXUS FINANCE PTY LTD	6.14	8.479	5.566	2.913
7	ENVESTRA VICTORIA PTY LT	4.62	6.723	5.424	1.298
8	LEIGHTON FINANCE LTD	3.41	8.776	5.320	3.457
9	SYDNEY AIRPORT FINANCE	4.35	8.389	5.396	2.994
10	MIRVAC GROUP FUNDING LTD	4.04	8.061	5.374	2.687
11	MIRVAC GROUP FINANCE LTD	5.54	8.349	5.516	2.833
12	NEW TERMINAL FINANCING C	5.56	9.042	5.518	3.524
13	BBI DBCT FINANCE PTY	5.28	10.273	5.494	4.779
14	SANTOS FINANCE LIMITED	4.56	6.939	5.418	1.521
15	WESFARMERS LTD	3.53	6.990	5.340	1.650
16	WESFARMERS LTD	3.53	7.011	5.340	1.671

Source: Authority's calculations

Retrospective analysis

597. The Authority has also carried out the retrospective analysis (or backdated test) of the bond yield approach for the period from November 2005 to October 2007 – the latest period Bloomberg's estimate of its fair yield curve for 10-year BBB Australian corporate bonds was available.

598. By using all the selection criteria stated in the bond yield approach and searching on the Bloomberg data terminal, 67 Australian corporate bonds were found. Of these, only 14 bonds have historical pricing data. Most of the 14 bonds only have pricing data for the period from 29 March 2007 to 13 September 2007. As a result, the Authority is of the view that the period where data was available for all 14 bonds should be used to conduct a backdated test.

599. Three floating bonds are Bendigo and Adelaide Bank; CLP Australia Finance; and Santos Finance Limited (mature in 2011). Their traded margins are converted into annualised fixed equivalent yield to maturity.

600. Australian corporate bonds that satisfy all the selection criteria for the bond yield approach are presented in Table 39 below.

Table 39. BBB-/BBB/BBB+ Corporate Bonds, March-September 2010

No.	Name of business	Bloomberg ticker	Coupon	Maturity
1.	BENDIGO AND ADELAIDE BK	EG297494 Corp	5.3667	28/03/2012
2.	CLP AUSTRALIA FINANCE	EF167972 Corp	5.57	16/11/2012
3.	CLP AUSTRALIA FINANCE	EF167960 Corp	6.25	16/11/2012
4.	PUBL & BROAD FINANCE LTD	ED928366 Corp	6.28	6/05/2011
5.	ENERGY PARTNERSHIP GAS	ED554437 Corp	6.375	29/07/2011
6.	DEXUS FINANCE PTY LTD	EG150658 Corp	6.75	8/02/2011
7.	NEW TERMINAL FINANCING C	EF641357 Corp	6.25	20/09/2016
8.	ORIGIN ENERGY LIMITED	EF736322 Corp	6.5	6/10/2011
9.	BBI DBCT FINANCE PTY	EF461870 Corp	6.25	9/06/2016
10.	SNOWY HYDRO LIMITED	EC870795 Corp	6.5	25/02/2013
11.	SANTOS FINANCE LIMITED	EF100832 Corp	5.44	23/09/2011
12.	SANTOS FINANCE LIMITED	EF102609 Corp	6.25	23/09/2015
13.	TABCORP INVESTMENT NO 4	ED640649 Corp	6.5	13/10/2011
14.	COLES GROUP FINANCE	EF023185 Corp	6	25/07/2012

Source: Bloomberg

601. The result for the backdated test for the Authority's bond yield approach and Bloomberg's estimate of the fair yield curve for 10-year BBB Australian corporate bonds for the period from 29 March 2007 to 13 September 2007 is summarised in Table 40 below.

Table 40. Backdated Test: Bond yield approach vs. Bloomberg's estimate of fair yield for 10-year BBB bonds, (per cent)

Bond Sample	Bond Yield Approach	Bloomberg's fair yield for 10-year BBB bonds	Difference
All 14 bonds	0.989	1.326	0.336
11 bonds (exclude 3 floating bonds)	1.192	1.326	0.133

Source: Authority's calculations

602. The Authority notes that the difference between the bond yield approach and Bloomberg's estimate of 10-year BBB fair yield for the period March-September 2007 is 0.336 per cent. In comparison, when the debt risk premium derived from the bond yield approach is compared with Bloomberg's estimate of 7-year BBB fair yield for the November-December 2010 period, the difference is more than one per cent.

603. In addition, for the backdated test, the difference is smaller, at only 13 basis points, when all three floating bonds, namely Bendigo and Adelaide Bank (2012); CLP Australia Finance (2012); and Santos Finance (2011) are excluded from the benchmark sample (Bloomberg does not include floating bonds in the sample to construct its fair value curves).

604. This backdated test provides further evidence on the robustness of the bond yield approach. As a result, the Authority is of the view that the bond yield approach should be used to estimate the debt risk premium for regulated businesses.

Draft Decision on Debt Risk Premium

605. The Authority considered four scenarios regarding the bond yield approach based on the public submissions received in response to the Authority's Discussion Paper on Debt Risk Premium:

- A full sample of 16 Australian corporate bonds (Scenario 1);
- A shortened sample excluding all bonds with BBB- credit rating (Scenario 2);
- A shortened sample excluding all bonds with less-than-5-year term to maturity (Scenario 3);
- A shortened sample excluding all bonds with BBB- credit rating and all bonds with less-than-5-year term to maturity (Scenario 4).

606. For each of the four scenarios above, the following four weighted average methods, which were previously discussed, are considered:

- a simple average;
- a term-to-maturity weighted average approach;
- an amount-issued weighted average approach; and
- a median approach.

607. The debt risk premiums calculated under the different scenarios and different weighted average approach are summarised in Table 41 below.

Table 41. Debt Risk Premiums under various scenarios and weighted average approach, (Per cent) as at 28 February 2011

Weighted Average Method	Scenario 1 (16 bonds)	Scenario 2 (12 bonds)	Scenario 3 (8 bonds)	Scenario 4 (6 bonds)	Simple Average of all 4 scenarios
Simple Average	2.888	2.810	3.453	3.289	3.110
Term to Maturity Weighted Average	2.999	2.875	3.413	3.207	3.124
Amount Issued Weighted Average	2.922	2.760	3.371	3.172	3.056
Median	2.903	2.863	3.218	2.903	2.972

Source: Authority's calculations

608. The Authority is of the view that the best estimate of the debt risk premium for the DBNGP is to use the term to maturity weighted average: bonds in the benchmark sample with longer term to maturity will be assigned higher weight, and as a result, account for more significance in the value of debt risk premium for the sample. This view is consistent with a basic finance principle in which a longer term investment is expected to be compensated with a higher return.

609. The Authority is of the view that a simple average of the term to maturity weighted average of all four scenarios is likely to reflect the current conditions in the market for funds.

610. As a result, for the 20 trading day period till 28 February 2011 for the Draft Decision for DBNGP, the Authority is of the view that the debt risk premium of 3.124 per cent is reasonable.

611. The adoption of the debt risk premium of 3.124 per cent would also reflect a conservative position. The Authority views this decision as conservative because:

- the sample of 16 bonds observed from the market includes bonds with the feature of "Callable" redemption which, in principle, require a higher yield to compensate bondholders. The bonds issued by the Bank of Queensland Ltd and BBI DBCT Finance Pty are callable bonds. There are no bonds issued with the feature of "Putable" redemption. It is unlikely that there will be bonds with the feature of "Putable" redemption issued in the Australian bond market in the foreseeable future;
- the sample of Australian corporate bonds includes BBB and BBB- bonds which, in principle, have higher yields in comparison with BBB+ credit rating bonds for regulated business; and
- the regulated businesses have access to bank finance which, currently, is likely to be a lower cost of borrowing in comparison with bond yields.

612. The Authority does not approve DBP's proposal in relation to debt raising costs of 44 bps to 65 bps depending on the market in which debt finance is sourced. The Authority notes that it is appropriate to make an allowance for debt raising costs of 12.5 basis points, on the basis that such an allowance is ordinarily appropriate and provided for by Australian regulators.

613. Debt raising costs may include underwriting fees, legal fees, company credit rating fees and any other costs incurred in raising debt finance. In practice, regulators across Australia have typically included an allowance of 12.5 basis points for these costs in the cost of debt as an increment to the debt margin.

614. The current allowance for debt raising costs of 12.5 basis points is based upon a benchmark analysis conducted by the Allen Consulting Group (**ACG**) in 2004.[332] The ACG undertook a study for the ACCC in 2004 on appropriate debt and equity raising costs to be included in costs recognised for the purposes of determining regulated revenues and prices. This study determined debt raising costs based on long-term bond issues, consistent with the assumptions applied in determining the costs of debt for a benchmark regulated entity. Debt raising costs were based on costs associated with Australian international bond issues and for Australian medium term notes sold jointly in Australia and overseas. Estimates of these costs were equivalent to 8 to 10.4 basis points per annum when expressed as an increment to the debt margin.[333] However, for regulatory certainty, Australian regulators have adopted a debt raising cost of 12.5 basis points.

615. The Authority's decision is not only based on the ACG 2004 study, which provided the debt of raising cost of 12.5 basis points, but also on the evidence recently provided to the AER by Associate Professor Handley from the University of Melbourne in April 2010.[334] The Authority is also of the view that an allowance of 12.5 basis points provides regulatory certainty given that this amount has been widely used in the past by Australian regulators.

616. In conclusion, the Authority is of the view that an allowance for debt raising costs of 12.5 basis points is appropriate to be included in the debt risk premium to calculate the total cost of debt for DBP.

617. The Authority considers that an appropriate credit rating for the DBP is BBB+. This is consistent with the Authority's recent Final Decision on the proposed access arrangement for the Goldfields Gas Pipeline in May 2010 and also in the Final Decision on the Proposed Revision to the Access Arrangement for the Western Australian Gas Networks in February 2011.

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[332] Allen Consulting Group, December 2004, Debt and equity raising transaction costs: Final report to ACCC.

[333] Allen Consulting Group, December 2004, Debt and Equity raising transaction costs: Final report to ACCC.

[334] Handley, J., April 2010, A Note on the Completion Method, Report prepared for the Australian Energy Regulator.

618. The Authority does not approve DBP's proposal in relation to the cost of debt of 9.73 per cent. The Authority considers that a reasonable cost of debt is 8.71 per cent, including the debt risk premium of 3.124 per cent for BBB+ as at 28 February 2011 derived using Bloomberg data for a sample of Australian corporate bonds; an allowance for debt raising costs of 0.125 per cent; and the nominal risk free rate of 5.46 per cent.

Gearing

DBP's Proposed Revisions

619. DBP submits that a gearing level of 60 per cent is the efficient level of gearing for DBP.[335] DBP notes that this assumed ratio of 60 per cent is consistent with the Authority's previous determinations for the DBP, as well as with the AER's decisions on the gearing of a benchmark efficient service provider in electricity or gas. The gearing level under the current Access Arrangement is also 60 per cent.

Submissions

620. The Authority has not received any public submissions in relation to DBP's proposed gearing level.

Considerations of the Authority

621. Gearing refers to the proportions of the value of the regulated business assumed to be financed by debt and equity. Financial gearing refers to the ratio of debt to total asset value. The relative proportions of debt and equity that a firm has outstanding constitute its capital structure. The capital structure choices differ across industries, as well as for different companies within the same industry.

622. The benchmark gearing ratio is considered to be the capital structure of a benchmark efficient utility business. The Authority assumes that the regulated business tends towards the benchmark gearing level in the long-run. As the optimal level of gearing is not directly observable, the 60/40 gearing level is derived from the average of actual gearing levels from a group of comparable firms.[336] The actual proportion of debt and equity for each business is dynamic and depends on a number of business-specific factors.

623. The Authority agrees that DBP's proposed gearing level of 60 per cent is consistent with the approach taken in relation to the current Access Arrangement and the approach taken in the AER electricity WACC Review, as well as being otherwise consistent with regulatory precedent and with observed levels of gearing of Australian pipeline companies.

624. The Authority approves DBP's proposal that the appropriate debt to total assets ratio (gearing level) is 60 per cent and the equity to total assets ratio is 40 per cent.

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335 DBNGP Revised Access Arrangement Proposal Submission, p. 25.

336 Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters.

Corporate Tax Rate

DBP's Proposed Revisions

625. DBP proposes to adopt the current corporate tax rate of 30 per cent to calculate a pre-tax WACC.[337] The corporate tax rate under the current Access Arrangement is also 30 per cent.

Submissions

626. The Authority did not receive any public submissions regarding the proposed corporate tax rate.

Considerations of the Authority

627. There has been some debate amongst regulators as to whether WACC determinations should use the statutory corporate tax rate (30 per cent), or effective tax rates.[338] Many companies have effective tax rates that are well below the statutory rate and there is a risk that using the statutory tax rate will overestimate the returns required by companies to meet tax obligations. However, verifying an individual company's effective tax rate would require modelling of taxation cash flows. The benefit of using the statutory rate as a benchmark assumption is that it is simple to apply.

628. The Authority has in previous WACC determinations assumed the effective taxation rate of the utility businesses to be equal to the statutory rate of corporate income tax.

629. The Authority agrees with DBP's proposal with respect to the corporate tax rate of 30 per cent.

630. The Authority approves DBP's proposal for a corporate tax rate of 30 per cent.

Value of Imputation Credits (Gamma)

DBP's Proposed Revisions

631. DBP argues that the estimates of imputation credits (gamma) used by the AER (0.65) and by the Authority (in the range of 0.57 to 0.81) have not been arrived at on a reasonable basis and as such they do not represent the best estimates possible in the circumstances.[339]

632. DBP, based on advice by its consultant, the Strategic Finance Group Consulting (**SFG**), submits that:[340]

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337 DBNGP Revised Access Arrangement Proposal Submission, p. 26.

338 IPART, 2002, The weighted average cost of capital (WACC): Discussion paper.

339 DBNGP Revised Access Arrangement Proposal Submission, p. 27.

340 DBNGP Revised Access Arrangement Proposal Submission, p. 27.

- market practice is to set gamma to zero or, equivalently, to make no adjustment to the WACC in relation to any assumed value of franking credits;
- current market evidence supports a value of gamma within the range of 0 to 0.23; and
- the evidence indicates a point estimate of 0 – there is no evidence which supports a value of gamma above 0.23.

633. DBP is of the view that a value of gamma of 0.2, based on the advice by the SFG, is in accordance with rule 87(2).[341]

634. For ease and clarity of the Authority's consideration regarding the value of imputation credits from the SFG report, SFG's submissions on the value of imputation credit are addressed in Appendix 3 of this draft decision. The key proposals from the SFG are summarised as follows:

- *Market practice*: The argument is that market professionals make no adjustment for imputation credits (or setting gamma to zero).
- *Assumed payout ratio*: The view is that payout ratio cannot be 1.0.
- *Conceptual issue*: The concept of domestic CAPM, which is adopted by the AER based on its consultant Associate Professor Handley, in which foreign investors are recognised to a certain extent, is flawed.
- Appropriate time period for estimating theta:

  The assumption of the structural break in July 2000 in the 2006 Beggs and Skeels study is flawed.
- Inferring theta from market prices:

  A more recent dividend drop-off study by the SFG should be used instead of the 2006 Beggs and Skeels study.
- Use of tax statistics to estimate theta:

  The argument is that the use of the average redemption rate reported by the ATO in the tax statistics approach to estimate theta is problematic.
- *Consistency issues:* A payout ratio of 1.0 or 0.71 needs to be used consistently in all WACC estimates.

  Also, the value of cash dividend per dollar (of either 100 cents per dollar or 75-80 cents per dollar) needs to be used consistently in estimating the value of gamma and equity return.
- *General observations:* Non-resident investors receive a return that is lower than the equilibrium required return because they cannot utilise the value of imputation credits.

341 DBNGP Revised Access Arrangement Proposal Submission, pp 27.

Submissions

635. In its submission, BHP Billiton submits that it is inappropriate to make no allowance for the value of imputation credits (i.e. setting gamma to be zero). BHP Billiton argues that the presence of Australian investors in the DBNGP means that gamma cannot be set to zero.[342] BHP Billiton also submits that the proposed value of gamma of 0.2 by DBP is not supported. BHP Billiton supports a value of gamma from 50 to 65 per cent, based on previous decisions by Australian regulators.

Considerations of the Authority

636. The Authority notes that the SFG report on the estimates of gamma is in response to the AER's decision on the value of gamma in its 2009 WACC Review. As such, the Authority has considered the AER's responses to these issues, together with the Authority's position in its recent determinations. For convenience, the Authority provides its decisions in response to each issue raised by SFG on behalf of DBP.

Market practice

637. First, SFG submits that market professionals make no adjustment for imputation credits when estimating WACC or when valuing firms. The Authority considers the advice of McKenzie and Partington (2010)[343] to the AER. McKenzie and Partington advised that the 2008 Truong, Partington and Peat study[344] found that the majority of firms do not account for the value of imputation credits because it is too difficult to do so. In addition, this study also finds that only 6 out of 89 firms surveyed cited that the reason they did not incorporate a value for gamma was because they considered that imputation credits have zero market value.

638. In addition, in the advice to the AER, Handley[345] states that, under the conventional approach to valuation (i.e. no imputation credits), Australian firms and independent valuation practitioners recognise that there is no explicit recognition of the value of imputation credits in either the cash flows or in the discount rate. As such, imputation credits are not assumed to have zero value but rather they are simply not explicitly taken into account in either the cash flows or in the discount rate.

639. Based on the above considerations, together with the fact that imputation credits have value to investors, the Authority is of the view that setting the value of gamma to zero is not appropriate.

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342 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, pp. 31-32.

343 McKenzie and Partington, Report to the AER, Evidence and submissions on gamma, 25 March 2010, pp. 27-28.

344 G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008.

345 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, pp. 3-4.

640. Second, the Authority notes that, based on Handley's advice[346] to the AER, the value of the firm is equal to the capitalised value of the conventionally measured cash flow (i.e. excluding the value of imputation credits) using a conventionally measured WACC (i.e. excluding the value of imputation credits). Importantly, this is simply the standard conventional approach to valuation, commonly used by practitioners and involves no explicit recognition of the value of imputation credits in either the cash flows or in the discount rate. As such, the Authority considers that SFG's argument cannot be justified.

Assumed payout ratio

641. The Authority considers that the assumed payout ratio of 1.0 is appropriate. This view is based on the following considerations:

- First, the payout ratio in any one year is approximately 71 per cent, as estimated by the 2004 Hathaway and Officer study.[347]
- Second, the Authority is aware that the AER considers that retained imputation credits that are not paid out immediately are likely to have value to investors.[348]
- Third, based on McKenzie and Partington's advice to the AER, these two authors state that empirical evidence from Hubbard and Kemsley (2001), and Ricketts and Wilkinson (2008), supported the view that retained imputation credits have positive value.[349]
- Fourth, in Handley's advice to the AER, the author states that the general consensus is the observed payout ratio in any one year is approximately 70 per cent, but that the issue of contention is the likely value of retained imputation credits. In addition, Handley states that the likely value of retained imputation credits cannot be reliably estimated without significant further research, including the estimation of a further three parameters: (i) the payout ratio; (ii) the discount rate for retained imputation credits; and (iii) the expected retention period.[350]
- Fifth, Handley advised the AER that the Officer WACC framework clearly assumes that cash flows continue into perpetuity, which is equivalent to assuming a 100 per cent payout ratio.[351]

Conceptual issues

642. The Authority considers Handley's advice to the AER on the issue.[352] Handley's view can be summarised as follows.

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346 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, p. 9.

347 Hathaway and Officer, *The value of imputation tax credits – Update 2004,* Capital Research Pty Ltd, November 2004.

348 The Australian Energy Regulator, May 2010, Final Decision, Queensland Distribution Determination, 2010-11 to 2014-15, p. 216

349 McKenzie and Partington, Report to the AER, Evidence and submissions on gamma, 25 March 2010, pp. 27-28.

350 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, pp. 35-38.

351 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, p. 40.

- First, Handley states that SFG is correct in suggesting that the derivation of the CAPM requires a closed system. However, SFG is incorrect in suggesting that this means that no investor within the model can hold any assets outside the model. This is because SFG have failed to take account of the implicit assumption of market segmentation which automatically occurs when one chooses a proxy for the market portfolio which does not include all the assets in the economy. Handley's interpretation is that segmentation does not imply that there are no other assets outside the model and that there are no other investors outside the model. Segmentation means that any assets outside the model, whether they are held by investors outside the model or by investors inside the model – and the corresponding wealth of those holdings of outside assets – are irrelevant for the purposes of pricing the assets inside the model.
- Second, Handley argues that if foreign investors were to be given a weighting commensurate with their global level of wealth then consistency considerations would require that the AER adopt an international CAPM for pricing purposes – which in turn would also require the use of an international risk free rate, an international market portfolio and stock betas measured relative to this international market portfolio. However, the current context is that the domestic version of CAPM is used.
- Based on the above observations, the Authority agrees with the AER that there is no conceptual issue regarding the use of the domestic CAPM for the purpose of estimating the cost of capital for regulated businesses in Western Australia.

Appropriate time period for estimating theta

643. SFG submitted that the Beggs and Skeels (2006) estimates for the year 2000 were unreliable. SFG submitted the AER inappropriately concluded that a structural break occurred following the 2000 tax regime change based on these unreliable estimates.

644. The Authority considers that there are strong conceptual grounds for assuming a structural break following the 2000 tax regime change. It is because this change allowed the full rebate of imputation credits in excess of tax liabilities, which was not previously allowed. This was also supported by conclusions of the 2006 Beggs and Skeels study. In this study, the authors separate the estimates of theta for each individual year from 2000 to 2004.[353] The results illustrate that while the value of cash dividends remains relatively stable at around 0.8 for each year in the period 2000 to 2004, there is an increase in the values of theta in the post-July 2000 period. All these estimates are statistically significant at a five per cent level of confidence. In addition, the 2006 Beggs and Skeels study also illustrates that the change in the 2000 tax regime had a permanent impact on the value of imputation credits based on results from the 1998 – 2000 interval and 2001 – 2004 interval.

645. Based on the above considerations, the Authority is of the view that there is evidence of a structural break following the 2000 tax changes.

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352 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, pages 11-4.

353 D. Beggs and C. L. Skeels, 'Market arbitrage of cash dividends and franking credits', The Economic Record, vol.82, no.258, September 2006, pp. 247-248.

Inferring theta from market prices (using the dividend drop-off study)

646. The Authority is aware that the AER considers that the 2010 SFG study to estimate the value of theta is not reliable on the following grounds.[354]

- Within the same sub–sample period of 1 July 2000 to 1 May 2004, the SFG study produces significantly different results to the 2006 Beggs and Skeels study. For this reason the AER considers that the SFG study's methodology is likely to materially differ from the 2006 Beggs and Skeels' methodology.
- Further, McKenzie and Partington noted that SFG's estimates are likely to be affected by multi-collinearity as well as other data and methodological issues, which suggests that SFG's theta estimate of 0.23 is unreliable.

647. In addition, SFG also submitted that dividend drop–off estimates of theta are conditional on the particular value of cash dividends that is adopted. However, the Authority notes that McKenzie and Partington's (2010) advice states that placing restrictions on parameters may bias the least squares estimate unless the restrictions are true.[355] As such, the Authority agrees with the AER that setting the value of a dollar of cash dividends to 100 cents in the context of estimating theta using dividend drop–off studies by the SFG is not appropriate.

Use of the tax statistics approach to estimate theta

648. The Authority considers three propositions raised by SFG regarding the use of tax statistics (i.e. using the average redemption rate of imputation credits reported by the ATO) to estimate theta.

649. First, SFG submitted that the AER's conclusion in the WACC review was that an increase in gamma will not decrease the cost of equity to the firm. However, the Authority notes that the AER[356] actually concluded that for any assumed value of gamma the total return to the shareholder will remain the same and thus the value of the firm will remain the same.

650. Second, the Authority notes that Handley[357] distinguished two types of cost of equity. The conventional cost of equity represents the "after-company-after-some-personal tax" cost of equity, because company profits have been taxed before they are paid out as dividends to shareholders. The grossed-up cost of equity represents the "after-company-before-personal tax" cost of equity because the payment of imputation credits removes the effect of taxation on company profits that are eventually paid out as dividends. As such, the investor will not be double taxed on their dividend returns – the imputation credits paid can be collected from the tax office either as an offset or a tax refund.

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354 The Australian Energy Regulator, May 2010, Final Decision, Queensland Distribution Determination, 2010-11 to 2014-15, p. 223

355 McKenzie and Partington, Report to the AER, Evidence and submissions on gamma, 25 March 2010, page 46.

356 The Australian Energy Regulator, May 2010, Final Decision, Queensland Distribution Determination, 2010-11 to 2014-15, p. 219

357 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, p. 10.

- Conventional cost of equity: $r_e^{adjusted} = r_e \times \left[\frac{1-T}{1-T\times(1-\gamma)}\right]$; and
- Grossed-up cost of equity: r_e

651. Handley demonstrated that if the change to the grossed-up cost of equity is correctly incorporated, an increase in gamma would also increase both the grossed-up cost of equity and the conventional cost of equity.[358]

652. By stating the second proposition that the removal of foreign shareholders would decrease the cost of equity if taxation redemption rates are used, Handley is of the view that SFG appears to mis-state the adjustment formula by mixing up $r_e^{adjusted}$ with r_e.

653. Third, the Authority is aware that the AER reconfirms its position that the assumption that theta would increase following a reduction in foreign investors is a reasonable assumption with a strong basis.[359] This is because domestic investors are likely to value imputation credits more highly than foreign investors. This is readily reflected in estimates of theta from tax statistics and theory would suggest that this is also likely to be true under market based estimates of theta, such as dividend drop–off studies.

654. In conclusion, based on the observations above, the Authority is of the view that estimating the value of theta using the tax approach employed by the AER is appropriate. The Authority's decision is based on the fact that estimates of theta from dividend drop-off studies experience issues, which have been previously discussed.

Consistency issues

655. The Authority is aware, based on Handley's advice to the AER,[360] that two classes of empirical evidence were relied upon:

- First, U.S. dividend yield studies provide evidence that dividends are "fully valued" – cash dividends are valued at 100 cents per dollar. This means that differential taxes have no effect on prices, and so differential taxes do not need to be taken into account in estimating equity returns.
- Second, U.S. dividend drop-off studies provide evidence that dividends are "less than fully valued", which means that cash dividends are valued at less than 100 cents in the dollar (due to the impact of differential taxes), and so differential taxes do need to be taken into account in estimating gamma.

358 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, p. 21.

359 The Australian Energy Regulator, May 2010, Final Decision, Queensland Distribution Determination, 2010-11 to 2014-15, p. 221

360 Handley, Report prepared for the Australian Energy Regulator on the estimation of gamma, 19 March 2010, pp. 24-25.

656. As such, Handley is of the view that the AER, in its 2009 WACC Review, is relying on the appropriate evidence in the appropriate context (i.e. U.S. dividend yield studies in relation to the CAPM and U.S. drop-off studies in relation to gamma).

657. Based on the above considerations, the Authority is of the view that there is no inconsistency when the estimates of the value of cash dividends are used differently: (i) 75-80 cents per dollar when theta (then gamma) is estimated and (ii) 100 cents per dollar when return on equity is estimated.

General observations

658. The Authority has considered the AER's decision on the same basis. The Authority agrees with the AER's view that imputation credits are likely to have some value to non-resident investors, even though it is likely to be less than the value of imputation credits to domestic investors. In addition, non-resident investors can sell shares to domestic investors who are able to utilise imputation credits. Moreover, there may be other tax agreements with foreign countries that may enable the utilisation of imputation credits by non-resident investors.[361]

Authority's position

659. A full imputation tax system for companies has been adopted in Australia since 1 July 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below), many other countries have a partial imputation system, where only partial credit is given for the company tax.

660. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

661. It is widely accepted that the approach adopted by regulators across Australia to define the value of imputation credits, known as "gamma" (γ), is in accordance with the Monkhouse definition.[362] There are two components of gamma:

- the payout ratio (F); and
- theta (θ).

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361 The Australian Energy Regulator, May 2010, Final Decision, Queensland Distribution Determination, 2010-11 to 2014-15, p. 221

362 Monkhouse, P. 'Adapting the APV Valuation Methodology and the Beta Gearing Formula to the Dividend Imputation Tax System', *Accounting and Finance*, 37, vol. 1, 1997, pp. 69-88.

662. As a result, the actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of (i) the franking credits that are created by the firm and that are distributed (the payout ratio, F); and (ii) the value that the investor attaches to the credit (theta), which depends on the investor's tax circumstances (that is, their marginal tax rate). As these will differ across investors, the value of franking credits may be between nil and full value (i.e. a gamma value between zero and one). A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation credits and therefore require a higher pre-tax income in order to justify investment.

663. In considering the value of imputation credits, the Authority has had regard to the detailed consideration given by the AER to this element of the WACC calculation.[363]

Payout Ratio (F)

664. The AER has adopted a distribution rate (F) of 1.0, reflecting advice that this assumption is consistent with a standard assumption of valuation practice that all free cash flows are paid out to investors.[364] On this basis, the AER has rejected the use of empirically observed market average distribution ratios. Advice to the AER also indicates that an assumed distribution rate of 1.0 is consistent with the Officer WACC.[365]

665. In addition, the AER noted that the Officer WACC framework is a perpetuity framework, which includes a simplifying assumption that cash flows occur in perpetuity and are therefore fully distributed at the end of each period. The AER accepted the advice of its consultant, Associate Professor Handley, and noted that it would be inconsistent to assume that there is a full distribution of a service provider's free cash flow but not a full distribution of the imputation credits associated with that free cash flow.

666. The AER considers that the assumption of a zero value for retained imputation credits is inconsistent with the Officer WACC framework.

667. The AER is also of the view that the actual payout ratio is unlikely to be significantly less than 100 per cent, based on an observed payout ratio from tax statistics of 71 per cent and the assumption that retained imputation credits have a positive value.[366]

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363 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. 287 – 340. Australian Energy Regulator, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. 393 – 469.

364 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 302.

365 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, Attachment G: John C Handley, 12 November 2008, A note on the valuation of imputation credits.

366 The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p. 150

668. In its recent Final Decision in October 2010 on Victorian electricity distribution network service providers, the AER adopted the range of 0.7 and 1.0 for the payout ratio.[367] The lower bound of 0.70 is the average of the payout ratio of 0.71 from the 2004 Hathaway and Officer study[368] and 0.69 from the 2010 Hathaway study.[369] The upper bound of 1.0 is from the view that retained imputation credits will be distributed in future periods. This view is consistent with Handley's view that assuming retained imputation credits would never be distributed would be to assume that approximately $170 billion in retained imputation credits will never be paid out and are essentially without value.[370]

669. Based on the above analyses, the Authority considers that the payout ratio between 0.7 and 1.0 is appropriate.

Estimates of theta (θ)

670. The AER has considered two sources of information on the utilisation rate.

671. First, the AER has placed significant weight on an estimate of the utilisation rate (θ) of 0.57, derived in a dividend drop-off study over the period 2001 to 2004,[371] taking into account that this study:

- is directly relevant to the current imputation tax regime, assessing the value of imputation credits over the post-2000 period after changes in tax law that allowed Australian taxpayers to claim a full cash rebate for unused imputation credits;
- is able to be verified on the basis of statistical tests presented in the paper; and
- is an independent and credible published study that has been through the academic peer review process.

672. Second, the AER has had regard to estimates of the utilisation rate from taxation statistics, indicating a range of values of the utilisation rate, θ, from 0.67 (pre-2000) to 0.81 (post-2000) and a point estimate of 0.74.[372]

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367 Australian Energy Regulator, October 2010, Victorian electricity distribution network service providers: Distribution determination 2011 – 2015, p. 583.

368 Hathaway and Officer 2004, *The value of imputation tax credits – Update 2004,* Capital Research Pty Ltd, November 2004.

369 Hathaway, Imputation Credit Redemption – ATO data 1988 - 2008, Capital Research Pty Ltd, November 2010

370 Handley, Report prepared for the Australian Energy Regulator on "*Further issues relating to the estimation of gamma*", October 2010, p. 8.

371 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 327, citing Beggs, D. and Skeels C.L., 2006, Market arbitrage of cash dividends and franking credits, *The Economic Record* vol 82 no.258, p. 247. AER, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. xix, 466.

372 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p 333, citing Handley, J. C. and Maheswaran, K., A measure of the efficacy of the Australian Imputation Tax System, *The Economic Record* vol. 84 no. 264 p. 91. Australian Energy Regulator, May 2009, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. xix, xx, 466, 467.

673. The Authority does not agree with NERA's argument that the method using tax statistics should not be used to estimate the value of theta. This argument from NERA was rejected by the AER in its WACC Review in May 2009, which can be summarised as follows.[373]

674. First, the AER's consultant on the issue, Associate Professor Handley, argues that the utilisation rates estimated by Handley and Maheswaran (2008) are relevant to the analysis of gamma. Handley confirms that an average utilisation rate across all investors of around 70-80 per cent is reported in the 2008 Handley and Maheswaran study. This represents a simple average of utilisation rates across investors, which assumes the set of investors is indicative of the set of investors in the domestic market portfolio. As a result, Handley believes that this estimate of theta may be interpreted as a reasonable upper bound on the value of gamma.

675. Second, the redemption rate used in the 2008 Handley and Maheswaran study weights domestic and foreign investors according to their presence in the Australian financial market. The Authority has adopted a domestic CAPM framework in which foreign investors in the Australian financial market are recognised to the extent that they invest in the domestic financial market. As such, a tax statistics approach can produce an indication of the upper bound estimate of the utilisation rate.

676. In addition, in its most recent Final Decision on the South Australia Distribution Determination, the AER considers that the utilisation rate of 0.65, based on an estimate from tax statistics as well as an estimate from market prices, is better than a market-based estimate alone.[374]

677. The mid-point estimate of theta θ is 0.65, together with the payout ratio F of 1.0. This provides an estimate of 0.65 for gamma in all determinations after the 2009 WACC Review by the AER.

678. The Authority has recently determined a value of theta on the basis of two empirical studies: (i) the 2006 Beggs and Skeels study; and (ii) the 2008 Handley and Maheswaran study. A range of 0.37 to 0.81 was used in its Final Decision on the Proposed Revision to the Access Arrangement for the South West Interconnected Network in December 2009; and on the Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010.

679. However, a more recent study by SFG Consulting in 2009, compared with the 2006 Beggs and Skeels, produced an estimated lower utilisation rate of 0.37.[375] This study used the same data as Beggs and Skeels in 2006 (which analysed data up to 10 May 2004) but analysed a further period of 28 months of data (up to 30 September 2006). This estimate was verified by one of the authors, C. Skeels, in the 2006 study by Beggs and Skeels. Skeels concluded that:

373 Australian Energy Regulator, December 2008, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, pp. 452-454.

374 The Australian Energy Regulator, May 2010, Final Decision, South Australia Distribution Determination, 2010-11 to 2014-15, p. xxiv.

375 SFG Consulting, 2009, The value of imputation credits as implied by the methodology of Beggs and Skeels (2006), p. 3.

> "the only reasonable conclusion to be drawn is that the extended data set should yield more accurate parameter estimates for the 1 July 2000 onwards sub-sample than does the shorter data set." [376]

680. The Authority notes that the AER's view is that the 2009 SFG study is subject to methodological concerns. In its recent Final Decision for the South Australian Distribution Determination in May 2010, after taking account of the advice of its consultants, Professor Michael McKenzie, Associate Professors Graham Partington (University of Sydney) and Associate Professor John Handley (University of Melbourne), the AER considered that market-based estimates of theta in the form of dividend drop-off studies are subject to significant concerns due to noise in the data and the likely effects of multi-collinearity on the regression results. Nevertheless, the Authority notes that the AER does make use of information from previous dividend drop-off studies in coming to its position on a reasonable value for the utilisation rate.

681. Given the uncertainty about the estimates of the utilisation rate using dividend drop-off studies and tax studies, the Authority's position is to take a wide range of estimates of the utilisation rate. Overall, the Authority considers that a reasonable range for the value of theta is 0.37 to 0.81.

682. As a result, based on a payout ratio of a range of 0.7 and 1.0; and a theta of 0.37 and 0.81, the Authority concluded that a reasonable value of gamma, being the product of a payout ratio and theta, for this Draft Decision is 0.53

Draft Decision

683. The Authority does not approve DBP's proposal in relation to gamma. The Authority considers that a reasonable point estimate for gamma is 0.53 (or 53 per cent).

Nominal Risk Free Rate of Return

DBP's Proposed Revisions

684. DBP has approximated the risk free rate of return using the proxy of daily yield data for Commonwealth Government securities with terms to maturity of 10 years, reported by the Reserve Bank of Australia.

685. DBP proposes a nominal risk free rate of return of 5.48 per cent.[377] This is the average of 10-year Commonwealth Government Securities for the 20 trading days to 18 March 2010 as reported by the Reserve Bank of Australia.

Submissions

686. The Authority did not receive any public submissions in relation to the nominal risk free rate.

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[376] Skeels, C. 2009, A Review of the SFG Dividend Drop-Off Study. A report prepared for Gilbert and Tobin, p. 11.

[377] DBNGP Revised Access Arrangement Proposal Submission, p. 19.

Considerations of the Authority

687. The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth government bond is widely used as a proxy for the risk free rate in Australia. CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, the current practice of regulators is to average the yield on the indexed 10-year Commonwealth government bond for a period of 20 trading days as close as feasible before the day the decision is made.

688. The Authority notes that DBP proposed two different proxies for the nominal risk free rate:

- DBP proposed using the 10-year Commonwealth Government Securities[378] as the proxy for the nominal risk free rate to estimate the cost of equity, based on advice by its consultant NERA.
- DBP proposed using the Bank Bill Swap Rate[379] as the proxy for the nominal risk free rate to estimate the cost of debt, based on advice by its consultant AMP Capital.

689. The Authority is of the view that there should be only one proxy for the nominal risk free rate used in the calculations of the WACC.

690. The Authority is aware that recent decisions by some economic regulators in Australia, including the AER, generally use the implied yields on 10-year government bonds as a proxy for the nominal risk free rate. The Authority used a 20-day moving average[380] of observed rates of return on 10-year Commonwealth government bonds as an estimate of the risk free rate in previous decisions.

691. The Authority notes that regulatory practice in access pricing in Australia, including that of the Authority, has been to adopt a cost of debt based on a 10-year term-to-maturity assumption even though the regulatory period is typically for five years. This approach was considered appropriate by the ACT in 2003, on the following basis:[381]

- a 10-year maturity has been used for the risk free rate in the calculations of MRP using historical data; and
- considerations regarding the management of interest rate risk imply that the maturity of debt should attempt to match the maturity of the real assets being financed.

378 DBNGP Revised Access Arrangement Proposal Submission, p. 19.

379 DBNGP Revised Access Arrangement Proposal Submission, p. 23.

380 There are three different types of moving averages: (i) Simple Moving Average; (ii) Exponential Moving Average; and (iii) Weighted Moving Average, and they are all calculated slightly differently. However, all have a similar smoothing effect on the data, so that any unexpected changes on rates are removed, and, as a result, the overall direction is shown more clearly. For simplicity, the Authority adopts the simple moving average in its calculations.

381 Australian Competition Tribunal, *Application by GasNet Australia (Operations) Pty Ltd,* 23 December 2003

692. However, in recent advice to IPART in 2011, Professor Davis from the University of Melbourne argues that neither of the above arguments by the ACT have merit.[382]

693. First, Davis is of the view that the use of the 10-year bond rate in the MRP has no relevance for the determination of the appropriate maturity of debt in estimating the cost of debt.

694. Second, Davis challenged the view that the considerations of interest rate risk management imply that the maturity of debt should be matched with the maturity of the regulated assets being financed. Davis argued that this view is incorrect because it confuses maturity with considerations of interest rate exposure. He argues that the regulated assets involved in access pricing generate a future cash flow stream, which is reset every five years at regulatory determinations, in line with movements in market interest rates. Consequently, Davis is of the view that interest rate hedging requires a maturity of debt equal to the length of the regulatory period of five years.

695. Davis presents an example to illustrate that the appropriate choice for the maturity of debt is equal to that of the regulatory term. Davis shows that once this choice is made, the "present value principle" (or the "NPV = 0" rule) is achieved. This principle requires the present value of the cash flow stream associated with the return on and of an asset to equal the cost of the asset.

696. Davis' view is supported by Associate Professor Lally's published academic papers in 2003 and 2007; and consulting work for the QCA in 2004. Lally argued that:[383]

> If the regulator seeks to ensure that the present value of the future cash flows to equity holders equals their initial investment, i.e. the "NPV = 0" rule, then the only choice of term for the risk free rate that can achieve this is that matching the regulatory cycle.

697. In another study, Lally concluded that:[384]

> if the risk free rate is revised at the end of each regulatory cycle in accordance with the prevailing rate, then the appropriate rate is that matching the regulatory period. This holds even in the presence of cost and volume risks and risks arising from asset valuation methodologies.

698. The Authority's consideration of the term of the risk free rate has also been influenced by developments in the Australian regulatory environment:

- The Australian Energy Regulator's Review of the WACC parameters for electricity transmission and distribution network service providers in 2009.
- The Authority's discussion paper on the bond yield approach to estimating the debt risk premium released in December 2010.

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382 Davis, K. 2011, "Determining Debt Costs in Access Pricing", a report to IPART, page 1, February 2011

383 Lally, M. 2007, "Regulation and the Term of the Risk Free Rate: Implications of Corporate Debt", *Accounting Research Journal*, Volume 20, No. 2, 2007, pp. 73-80.

384 Lally, M. 2004, "Regulation and the Choice of the Risk Free Rate", *Accounting Research Journal*, Volume 17, No. 1, 2004, pp. 18-23.

- The Independent Pricing and Regulatory Tribunal of New South Wales (**IPART**) Draft Decision on "Developing the approach to estimating the debt margin" in February 2011.

699. These developments are discussed below.

The AER's WACC Review in 2008/09

700. In its WACC Review 2008/9, regarding the terms used in the calculations of the nominal risk free rate, the AER concluded that:[385]

- The possibility of over-compensation resulting from the use of a term for the risk free rate that exceeds the length of the regulatory period was not argued before the Tribunal in its GasNet decision.
- A term of the risk free proxy which matches the length of the regulatory period (i.e. 5 years) better reflects the financing strategies of regulated energy network businesses.
- Relative to a term assumption consistent with the length of the regulatory period (i.e. 5 years), the current 10-year term assumption is expected to result in net overcompensation on average, given the risk faced over the regulatory period. In other words, the use of a 10-year term assumption is expected to violate the 'present value principle', or the "NPV = 0" rule.
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701. Overall, in its Draft Decision released in December 2008, the AER was of the view that there is sufficient persuasive evidence to depart from the previously adopted 10 year risk free rate term assumption – as a term matching the regulatory period better reflects the weighted average maturity of outstanding debt portfolios, and results in correct compensation according to the 'present value principle'.

702. Further consultation by the AER revealed that the weighted average effective term of debt portfolios of the businesses as at the end of financial year 2007 after hedging was estimated at 7.37 years. As such, the AER concluded that a 10-year (or 5-year) term assumption is expected to over-compensate (or under-compensate) the benchmark efficient energy network business on the cost of debt.

703. In its Final Decision released in May 2009, the AER concluded that:[386]

> … despite the strong conceptual arguments for a term matching the length of the regulatory period on the equity side, the AER considers it is reasonable and appropriate to take a cautious approach on this matter and retain a 10-year term assumption. This reflects the AER's concern that refinancing risk not be increased for the sector, which is particularly important given the current market conditions.

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385 The Australian Energy Regulator, 2008, Explanatory Statement, "Electricity transmission and distribution network service providers: Review of the weighted average cost of capital parameters", pp. 133-134.

386 The Australian Energy Regulator, Final Decision, 2009, "Electricity transmission and distribution network service providers: Review of the weighted average cost of capital parameters", pp. 173-174.

IPART's Draft Decision on developing the approach to estimating the debt margin

704. On the advice of Professor Davis, in its draft decision, IPART concluded that:[387]

- There are strong theoretical grounds for matching the term assumption with the regulatory period. IPART's draft decision was to adopt a 5-year term.
- There is significant variation on the average term to maturity of debt issued by regulated utilities. There is, however, evidence to support the view that utilities typically ensure that no significant proportion of their debt funding matures in any one year.
- There is a regulatory precedent for a 10-year term assumption, although recently some regulators have sought to align the regulatory period with the term to maturity assumption.

The Authority's recent position on the debt risk premium

705. As previously discussed on the 'Debt Risk Premium' (paragraphs 514 to 618), the Authority is now using the bond yield approach to estimate the debt risk premium for the regulated businesses. The average term to maturity of Australian corporate bonds included in the benchmark sample of bonds used by the Authority is 5.43 years.

Draft Decision

706. The Authority does not approve DBP's proposal in relation to the calculation of the nominal risk free rate of return.

707. The Authority is of the view that there should be consistency between the terms of the risk free rate and the debt risk premium. This view is based on the following considerations.

708. First, the Authority notes that the possibility of over-compensation from the use of a term for the risk free rate that exceeds the length of the regulatory period was not argued before the Tribunal in its 2003 GasNet decision.

709. Second, the Authority is of the view that the use of a 10-year term assumption is expected to violate the "NPV=0" rule. This view is based on various studies by Lally and Davis.

710. Third, the Authority is of the view that there is no evidence to suggest that regulated businesses will seek to issue long term debt as a matter of preference. Instead, the Authority is aware that some regulated businesses secure finance over a period of less than 5 years.

711. Fourth, the Authority is aware that regulated businesses generally avoid the situation of having a significant proportion of their debt funding maturing in any one year.

[387] IPART, Draft Decision on "*Developing the approach to estimating the debt margin*"", p. 25, February 2011.

712. Fifth, the Authority is of the view that regulated businesses are active in hedging markets. This view is based on the Deloitte report in 2008 for the AER.[388]

713. Sixth, a term of the risk free rate which matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia. The Authority is of the view that the use of a term of 5 years matching the regulatory period will result in correct compensation consistent with the "NPV=0" rule.

714. In conclusion, based on the above considerations, the Authority is of the view that there are strong grounds for matching the assumption of term to maturity with the regulatory period, which is generally 5 years. The Authority considers the estimated nominal risk free rate of return should be 5.46 per cent using yields from the 5-year Commonwealth Government bonds reported by the RBA, as at 28 February 2011. Based on an estimated nominal risk free rate of return of 5.46 per cent and an assumed inflation rate of 2.65 per cent, the Authority estimates a real risk free rate of 2.74 per cent.

715. The Authority notes that these values will need to be updated at the time of the Final Decision, so as to be commensurate with prevailing market conditions at the time.

Expected Inflation

DBP's Proposed Revisions

716. DBP has used a widely accepted method to estimate the inflation rate which has been calculated as the geometric mean of the Reserve Bank of Australia's (**RBA**) inflation forecasts for the next 10-years. DBP proposes an expected inflation rate of 2.52 per cent.[389]

Submissions

717. The Authority did not receive any public submissions in relation to the expected inflation rate.

Considerations of the Authority

718. The Authority agrees with the general approach to determine the expected inflation rate adopted by DBP.

719. The Authority's approach to estimate the expected inflation has been to use the geometric mean of the Reserve Bank of Australia's inflation forecasts for the next ten years. The inflation forecasts for the next three years are in the RBA's Monetary Statement which are published quarterly and the forecasts for the last seven years being the midpoint of the RBA's inflation target of 2 per cent to 3 per cent, being the midpoint of 2.5 per cent.

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[388] Deloitte (2008) Australia Energy regulator – Refinancing, Debt Markets and Liquidity, Report to the AER, 12 November 2008.

[389] DBNGP Revised Access Arrangement Proposal Submission, p. 28.

720. The same general approach was adopted in the Authority's recent Final Decisions on the Proposed Access Arrangement for the Western Australia Gas Networks in February 2011; on the Proposed Access Arrangement for the Goldfields Gas Pipeline in May 2010' and on its Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009.

721. The Authority proposes to adopt the same general approach for this Decision. However, for consistency with the estimates of the debt risk premium and the calculations of the nominal risk free rate, which were discussed in detail above, the Authority has decided to depart from its previous position of using the assumed 10-year term to maturity. Instead, a 5-year the term to maturity is now assumed.

722. The forecasts on which the Authority relies for its calculations are all from the RBA's February 2011 *Statement on Monetary Policy*:[390]

- 2.50 per cent for the year to June 2011;
- 2.75 per cent for the year to June 2012;
- 3.00 per cent for the year to June 2013; and
- 2.50 per cent (being a mid-point estimate of the RBA's long term inflation forecasts) for each year for the next two years from July 2014.

723. Using the above forecasts, the Authority has calculated the forecast inflation rate for this Draft Decision of 2.65 per cent.

724. The Authority's approach produces the forecast inflation rate of 2.65 per cent, whereas DBP has proposed 2.52 per cent in its submission. The reason for this difference is that while the Authority is using the RBA's forecasts from its February 2011 *Statement on Monetary Policy*, DBP adopted the forecasts from the RBA's February 2010 *Statement on Monetary Policy* because of the date on which DBP's Information Submission was lodged with the Authority. In addition, the Authority adopts a 5-year term to maturity whereas DBP adopted the assumed 10-year term.

725. The Authority agrees with DBP's proposed method to calculate the forecast rate of inflation. However, a 5-year term to maturity is adopted. The Authority's calculation of expected inflation for the Draft Decision is 2.65 per cent. However, DBP's Proposed Revisions should be amended to allow for a forecast inflation rate to be calculated as above, which may result in a changed rate at the time of the Final Decision.

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[390] Reserve Bank of Australia, February 2011, *Statement on Monetary Policy*, available at http://www.rba.gov.au/publications/smp/2011/feb/pdf/0211.pdf page 60.

Market Risk Premium

DBP's Proposed Revisions

726. DBP submits that the market risk premium (MRP) of 6.5 per cent has been arrived at on a reasonable basis, and represents the best estimate possible in the circumstances. DBP also submits that the MRP of 6.5 per cent was adopted in the Authority's October 2009 Draft Decision on proposed revisions to the access arrangement for the Goldfields Gas Pipeline, and in its December 2009 Final Decision on Western Power's South West Interconnected Network.[391]

Submissions

727. In its submission, BHP Billiton submits that a MRP of 5-6 per cent is supported.[392] BHP Billiton draws its conclusion based on previously adopted values of 5 to 6 per cent by Australian regulators. In addition, BHP Billiton also submits the estimates of MRP from investment banks such as Merrill Lynch (with MRP of 5.0 per cent); Macquarie Research (5.5 per cent); GSJBW (6 per cent); RBS (6 per cent); Morgan Stanley (6 per cent) and Austock Securities (6 per cent). These estimates lead to the average of 5.75 per cent for MRP.

Considerations of the Authority

728. The Authority does not agree with DBP that it has adopted the MRP of 6.5 per cent in its May 2010 Final Decision on proposed revisions to the access arrangement for the Goldfields Gas Pipeline, and in its December 2009 Final Decision on Western Power's South West Interconnected Network. The Authority reconfirms its position, as previously indicated, that the MRP of 6.5 per cent was mistakenly interpreted the Authority's decisions by DBP.

729. In these two final decisions, the Authority has adopted the range of 5 per cent to 7 per cent with the view that the point estimate of 6 per cent as the reasonable estimate for the MRP is to be adopted.

Consideration of the Method of Using Historical Data

730. The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets.

731. It is the current practice of regulators across Australia to estimate the MRP using the historical data on equity premia.

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391 DBNGP Revised Access Arrangement Proposal Submission, p. 19.

392 BHP Billiton, submission to Dampier to Bunbury Natural Gas Pipeline: Proposed Revisions to the Access Arrangement, p. 67.

732. Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER's decisions after its review of WACC parameters released in May 2009. It is noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[393] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was based on cash flow measures.[394] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premia.

733. In its review of WACC parameters for electricity distribution and transmission networks in May 2009, the AER commissioned Associate Professor Handley at the University of Melbourne to update historical excess returns using full year data for 2008. The estimates for this study covered the periods of 1883-2008, 1937-2008, 1958-2008, 1980-2008 and 1988-2008, were relative to 10-year Commonwealth Government Securities, were grossed-up for a theta[395] of 0, 0.28, 0.5, 0.65 and 1.0 and included standard errors and 95 per cent confidence intervals. The results are presented in Table 42 below.

Table 42. Historical Excess Returns (Arithmetic Average, Relative to 10-Year Bonds, 'Grossed-up' for Value of Imputation Credits Distributed, Per cent)

Utilisation rate	0.00	0.28	0.5	0.65	1.00
1883-2008	5.9*	6.0*	6.1*	6.1*	6.2*
1937-2008	5.4*	5.5*	5.6*	5.7*	5.9*
1958-2008	5.7	5.9	6.1	6.2*	6.4*
1980-2008	5.0	5.3	5.6	5.8	6.3
1988-2008	3.8	4.3	4.7	5.0	5.6

*Indicates estimates are statistically significant at the five per cent level based on a two-tailed t-test.

Source: Handley (2009).[396]

734. The above estimates reveal that the most recent long-term historical average excess returns estimated over a range of long-term estimation periods (1883-2008, 1937-2008, 1958-2008), once 'grossed-up' for a utilisation rate of 0.65 and estimated relative to the yield on 10-year Commonwealth Government Securities, is close to 6 per cent (between 5.7 and 6.2 per cent).

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393 ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998.

394 ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998.

395 Theta is the value of a franking credit to investors at the time they receive it.

396 J. C. Handley, *Further comments on the historical market risk premium*, Report prepared for the AER, 14 April 2009, pp. 6-9.

735. An estimate of MRP of 6 per cent, from the AER's view, was the best estimate of a forward-looking long-term value for MRP prior to the onset of the global financial crisis under relatively stable market conditions with the assumption that there is no structural break which has occurred in the market. However, given the state of the international financial market at that time (May 2009), when relatively stable market conditions did not exist, and taking into account the uncertainty surrounding the global economic crisis, the AER considered that a MRP of 6.5 per cent was reasonable.

> "The AER considers that prior to the onset of the global financial crisis, ***an estimate of 6 per cent was the best estimate*** of a forward looking long term MRP, and accordingly, under relatively stable market conditions - assuming no structural break has occurred in the market - this would remain the AER's view as to ***the best estimate of the forward looking long term MRP***." [emphasis added] [397]

736. The current state of the Australian financial market has significantly improved, as evidenced by seven increases in the cash rate by the Reserve Bank of Australia since 7 October 2009. In its recent Statement on Monetary Policy Decision August 2010, the Reserve Bank stated that:

> "Activity in the Australian economy grew at a solid pace over the second half of 2010. Strong demand for Australian commodities is underpinning growth in national income and a high level of business investment, while growth in household consumption remains relatively subdued. The latest available data for real GDP show growth of 2.7 per cent over the year to September, with nominal income up by nearly 10 per cent over the year due to the increase in the terms of trade. Employment growth continues to be strong and business conditions – as measured by surveys – remain generally positive."[398]

737. The Authority is of the view that there is now evidence to suggest that market conditions have stabilised. This view is supported by the reports released by the Reserve Bank of Australia (**RBA**), the International Monetary Fund (**IMF**), and the Organisation for Economic Cooperation and Development (**OECD**). In all these reports, it is widely agreed that the Australian economy has displayed strong resilience and robustness during and after the 2008 Global Financial Crisis.

738. The RBA was of the view that:

> "Employment growth has been robust, business and consumer confidence is above average, the housing market has been strong, and there are signs that the period of business deleveraging is coming to an end. Collectively, these outcomes provide us with some confidence that the economy is now in a reasonably solid upswing."[399]

> and

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397 Australian Energy Regulator, May 2009, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, p. 175.

398 The Reserve Bank of Australia, (February 2011), Monetary Policy Decision, accessed at http://www.rba.gov.au/publications/smp/index.html, p. 25.

399 The Reserve Bank of Australia, May 2010, "Recent Developments in the Global and Australian Economies", available at http://www.rba.gov.au/speeches/2010/sp-ag-250310.html accessed on 8th December 2010.

"Our economy recovered relatively quickly from what was a shallow downturn following the global financial crisis, and over the past year has grown around its trend rate of 3¼ per cent. Domestic demand has grown substantially faster than this – about 5¼ per cent – due importantly to growth in public spending, though this is moderating now…

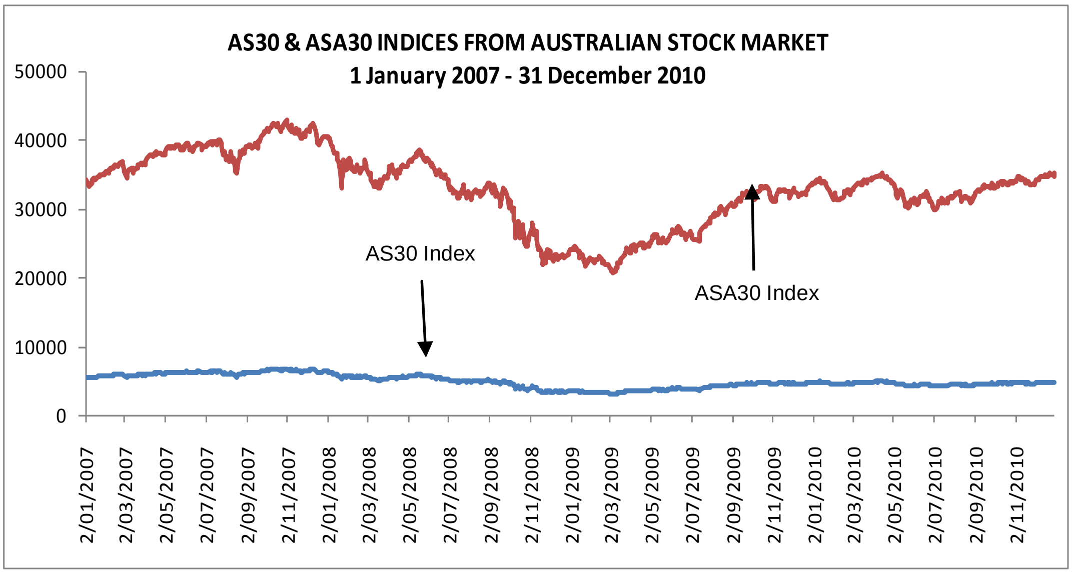
Business conditions are generally around average levels, although there are clear differences across sectors. Business investment is at a high level, particularly in the mining sector, and information published by the Australian Bureau of Statistics, as well as our own liaison with companies, suggests that it will pick up sharply further over the next couple of years".[400]

and

"In November, the Reserve Bank Board increased the target for the cash rate from 4.50 per cent to 4.75 per cent, the first change to the target in six months. Money market yields suggest markets currently expect a further increase in the cash rate in the first half of 2011".[401]

739. In addition, the Australian share market has significantly recovered from the crisis level. This view is confirmed in Figure 8 below.

Figure 8. ASX All Ordinaries Index (AS30 Index) and ASX Accumulation All Ordinaries Index (ASA30 Index).



Source: Bloomberg

740. In November 2010,the OECD concluded that:

"After weathering the crisis well in 2009, the Australian economy is projected to experience strong growth in 2010 and 2011, above its trend rate. Activity might expand by as much as 3¼ per cent and 3½ per cent in these two years, driven by booming exports and domestic demand. The unemployment rate is

400 The Reserve Bank of Australia, May 2010, "Recent Developments in the Global and Australian Economies", available at http://www.rba.gov.au/speeches/2010/sp-dg-181110.html accessed on 8th December 2010.

401 The Reserve Bank of Australia, November 2010, "Statement on Monetary Policy", available at http://www.rba.gov.au/publications/smp/2010/nov/html/index.html, accessed on 8th December 2010

> expected to fall below 5 per cent by the end of 2011, in a context of moderate inflation."
>
> "The Australian economy, fuelled by the mining boom, should grow robustly in 2011 and 2012 at a rate of between 3½ and 4%. Strong growth, driven by terms of trade gains and dynamic investment, will reduce unemployment.
>
> The projected increase in demand is likely to require a further tightening of monetary conditions to ensure that a non-inflationary recovery remains on track. The current fiscal consolidation plan must be pursued, as assumed in the projections, to rebuild the margins for manoeuvre used during the crisis. Reforms are needed to strengthen supply capacities in the housing and infrastructure sectors to reduce bottlenecks, which the mining boom is likely to exacerbate."[402]

741. The IMF shared the views of the RBA and the OECD with regard to conditions for Australian economy. They state that:

> The global downturn had a fairly small impact on the Australian economy, as real investment barely contracted in 2009 and the unemployment rate went up by less than 2 percentage points. Not surprisingly, Australia's potential growth is estimated to have declined by just 1/3 per cent to 3.1 per cent in 2009.[403]

742. The Authority also observes that 6.0 per cent is the market risk premium value most commonly used by market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 26 per cent of market practitioners apply values of MRP more than 6.0 per cent.[404] However, the Authority is aware that this information preceded the global financial crisis in 2008.

743. IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that MRP derived from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events such as the global financial crisis.

744. The Queensland Competition Authority has also used 6.0 per cent for MRP in the Draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction – therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term and not in response to short-term market fluctuations.

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402 The OECD, November 2010 "Economic outlook for Australian economy", available at http://www.oecd.org/document/15/0,3343,en_2649_34573_45268687_1_1_1_1,00.html accessed on 8th December 2010.

403 The Yan Sun, 'Potential Growth of Australia and New Zealand in the Aftermath of the Global Crisis', IMF Working Paper, WP/10/27, May 2010, pp. 19.

404 G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p.155.

745. The Authority is aware that the AER has adopted a MRP of 6 per cent in its most recent draft decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, on the following grounds.[405]

746. First, the estimates of historical excess returns for three periods up to 2010 provided by Associate Professor John Handley. These estimates are arithmetic means and with data available to the end of 2010 provide a range of 6.1 per cent to 6.6 per cent.

Table 43. Estimates of the Market Risk Premium (assumed value of gamma of 0.65), using arithmetic means

Period	MRP (per cent)	95 per cent confidence interval (per cent)
1883-2010	6.3	3.4 – 9.2
1937-2010	6.1	1.5 – 10.7
1958-2010	6.6	0.4 – 12.9

Source: Handley, *An estimate of the historical equity risk premium for the period for 1883 – 2010*, January 2011, page 8. A report for the AER

747. The AER notes that the above estimates of the historical equity risk premium are accompanied by very wide confidence intervals. As a result, there is low statistical precision in these estimates. The AER also notes that these estimates are not inconsistent with the estimates prior to the Global Financial Crisis.

748. Second, the AER considers that these estimates would be taken into account by investors. However, the investors' expectation of the long run forward looking MRP is unlikely to change annually in response to the latest historical estimates of the type calculated by Handley.

749. Third, the above estimates of the MRP in Table 43 use the arithmetic means. AER notes that using geometric means is more appropriate when annual returns are related to each other over time. As long as returns vary over time, a geometric mean will be less than an arithmetic mean. The greater the volatility in returns, the greater the difference between arithmetic means and geometric means. Using geometric means, the estimates of historical excess returns for three periods up to 2010 provided by Associate Professor John Handley are summarised in Table 44.

[405] Australian Energy Regulator, February 2011, Draft Decision, Envestra Ltd. – Access Arrangement proposal for the SA gas network, pages 83-92.

Table 44. Estimates of the Market Risk Premium (assumed value of gamma of 0.65), using geometric means

Period	MRP (per cent) Using Geometric means	MRP (per cent) Using Arithmetic means
1883-2010	4.9	6.3
1937-2010	4.1	6.1
1958-2010	4.1	6.6

Source: Handley, *An estimate of the historical equity risk premium for the period for 1883 – 2010*, January 2011, page 8. A report for the AER

750. Rather than using a complex weighted average approach, the AER is of the view that the estimates of the MRP using arithmetic means should be interpreted with the understanding that these estimates may overestimate the expected forward-looking MRP.

751. Fourth, in conclusion, the AER considers that the available evidence on the MRP is imprecise and is subject to a wide margin of variation. As a result, the AER is of the view that the MRP of 6 per cent is the best estimate of the forward-looking MRP.

752. The Authority adopts the same approach as in its Final Decisions on the Proposed Revisions to the Access Arrangement for the South West Interconnected Network in December 2009 and on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in May 2010, for the same reasons as applied in those decisions. This approach is consistent with historical regulatory practice. In these two final decisions, the Authority adopted the range of 5 to 7 per cent with the view that the point estimate of 6 per cent was a reasonable estimate for the MRP and was to be adopted.

753. In addition, the Authority adopted the MRP of 6 per cent in its most recent Final Decision on WA Gas Networks released in February 2011.

754. The Authority is of the view that a MRP of 6 per cent will be within the reasonable range of values. This is consistent with the view with some other Australian regulators, including IPART and QCA. The estimate of the MRP of 6 per cent also reflects the view by the AER that this is the best estimate of a forward-looking long-term MRP.

755. The Authority considers that a reasonable point estimate for the MRP is 6 per cent.

Rate of Return

756. Based upon the above assessment of each of the CAPM parameters, the point estimates that the Authority considers may reasonably be applied to the parameters of the CAPM in estimating the rate of return for DBP are as shown in Table 45 below.

Table 45. Authority's Required Amendments to DBP's Proposed Parameter Values for Determination of a Rate of Return as at 28 February 2011 (Per cent)

Parameter	Value (Per cent)
Nominal Risk Free Rate $\left(R_f\right)$	5.46
Real Risk Free Rate $\left(R_f^r\right)$	2.74
Inflation Rate π_e	2.65
Debt Proportion $\left(D\right)$	60
Equity Proportion $\left(E\right)$	40
Cost of Debt: Debt Risk Premium (DRP) (BBB+)	3.124
Cost of Debt: Debt Issuing Cost (DIC)	0.125
Cost of Debt: Risk Margin (RM)	3.249
Australian Market Risk Premium (MRP)	6
Equity Beta $\left(\beta_e\right)$	80
Corporate Tax Rate $\left(T_c\right)$	30
Franking Credit $\left(\gamma\right)$	53
Nominal Cost of Debt $\left(R_d^n\right)$	8.71
Real Cost of Debt $\left(R_d^r\right)$	5.90
Nominal Pre Tax Cost of Equity $\left(R_e^{n,\text{pre-tax}}\right)$	11.94
Real Pre Tax Cost of Equity $\left(R_e^{r,\text{pre-tax}}\right)$	9.05
Nominal After Tax Cost of Equity $\left(R_e^{n,\text{post-tax}}\right)$	10.26
Real After Tax Cost of Equity $\left(R_e^{r,\text{post-tax}}\right)$	7.41

Table 46. Estimates of WACC (Per cent)

WACC	Value (Per cent)
Nominal Pre Tax WACC $\left(WACC_n^{\text{pre-tax}}\right)$	10.00
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	7.16
Nominal After Tax WACC $\left(WACC_n^{\text{post-tax}}\right)$	9.33
Real After Tax WACC $\left(WACC_r^{\text{post-tax}}\right)$	6.51

757. The Authority does not approve DBP's proposal in relation to the rate of return.

758. Table 67 of the Access Arrangement should be amended to reflect the values in Table 45 of this Draft Decision.

Required Amendment 7

In relation to Rate of Return, Table 67 of the proposed revised access arrangement should be amended to reflect the values of CAPM and WACC parameters in Table 45 of this Draft Decision

759. For the purpose of this Draft Decision, the Authority adopts the point value, being a real pre-tax Rate of Return of 7.16 per cent.

Required Amendment 8

DBP's Proposed Revisions should be amended to adopt a real pre-tax rate of return of 7.16 per cent.

Taxation

Regulatory Requirements

760. Rule 76(c) of the NGR provides for the estimated cost of corporate taxation as a building block for total revenue insofar as this is applicable.

DBP's Proposed Revisions

761. Section 17.2 of the revised access arrangement information indicates that there are no amounts included in the total revenue calculation for each year of the 2011 to 2015 access arrangement period for the estimated cost of corporate income tax.

762. Section 12 of the revised access arrangement information specifies that an implicit allowance is made for the cost of corporate taxation through the use of a rate of return value that has been determined on a pre-tax basis.

Submissions

763. None of the submissions made to the Authority on the proposed revised access arrangement addressed the treatment of taxation costs.

Considerations of the Authority

764. DBP has proposed that costs of corporate income taxation be included in total revenue through use of a pre-tax rate of return in determining the values of returns on the capital base. The Authority concurs with this approach and, accordingly considers that the requirement of rule 76(c) to include an explicit allowance for taxation in the building block calculation for total revenue is not applicable.

Incentive Mechanism

Regulatory Requirements

765. Rule 98 of the NGR provides that a full access arrangement may include (and the Authority may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.

> 98 Incentive mechanism
>
> (1) A full access arrangement may include (and the AER [ERA] may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.
>
> (2) An incentive mechanism may provide for carrying over increments for efficiency gains and decrements for losses of efficiency from one access arrangement period to the next.
>
> (3) An incentive mechanism must be consistent with the revenue and pricing principles.

766. Rule 72(d) provides for total revenue to include amounts (as an increment or decrement) resulting from the operation of the incentive mechanism. Rule 71(1)(i) requires that the access arrangement information include the proposed carryover of the amounts and a demonstration of how allowance is to be made in the value of total revenue for the amounts.

DBP’s Proposed Revisions

767. The access arrangement for the 2005 to 2010 access arrangement period includes an incentive mechanism at clause 7.12. This incentive mechanism provides for an amount to be added to total revenue in each of the years of the 2011 to 2015 access arrangement period where DBP outperforms forecasts of operating expenditure in years of the 2005 to 2011 access arrangement period. The incentive mechanism is reproduced as follows.

> 7.12 Use of Incentive Mechanism
>
> (a) The adoption of the ‘price path’ approach is intended to provide an incentive to develop the market and reduce costs.
>
> (b) For the Access Arrangement Period commencing on 1 January 2011, the Total Revenue from which the Reference Tariff is to be determined is to include, in addition to the costs listed in clause 7.2(b) of this Access Arrangement, a share of any returns to Operator from the sale of Full Haul, Part Haul and Back Haul Services in the previous Access Arrangement Period that exceeded the level of returns that were expected during that previous Access Arrangement Period from the sale of such Services.

(c) The share of returns to Operator referred to in clause 7.12(b) of this Access Arrangement is to be calculated, for each year, as shown below:

Year	Share of returns
2011	$S_{2011} = E_{2006} + E_{2007} + E_{2008} + E_{2009}$
2012	$S_{2012} = E_{2007} + E_{2008} + E_{2009}$
2013	$S_{2013} = E_{2008} + E_{2009}$
2014	$S_{2014} = E_{2009}$
2015	$S_{2015} = 0$

where:

E_t = 0, if $[D_t - D_{t-1} \times (CPI_t/CPI_{t-1}) \times R_t] \times I_s \leq 0$, and $[D_t - D_{t-1} \times (CPI_t/CPI_{t-1}) \times R_t] \times I_s$, if $[D_t - D_{t-1} \times (CPI_t/CPI_{t-1}) \times R_t] \times I_s > 0$, for year t, where t = 2006, 2007, 2008, and 2009;

D_t = 0, if $(F_t - A_t) \leq 0$, and $(F_t - A_t)$ if $(F_t - A_t) > 0$;

R_t = adjustment required for real escalation applied to labour costs in year t, as shown in the following table: t

t	2006	2007	2008	2009
R_t	1.0044	1.0039	1.0041	1.0042

I_s = inflation factor for year s, where s = 2011, 2012, 2013, 2014, 2015, which adjusts $[D_t - D_{t-1}) \times (CPI_t/CPI_{t-1}) \times R_t]$ for inflation from year t to year s;

F_t = the forecast of non-capital costs for year t made for the purpose of determining the Reference Tariff for the current period from 1 January 2005 until 31 December 2010;

A_t = actual non-capital costs for year t;

F_{t-1} = the forecast of non-capital costs for year t – 1 made for the purpose of determining the Reference Tariff for the current period from 1 January 2005 until 31 December 2010;

A_{t-1} = actual non-capital costs for year $_{t-1}$;

CPI_t = CPI for the quarter ending on 30 September of year t; and

CPI_{t-1} = CPI for the quarter ending on 30 September of year t – 1.

(e) For the purposes of this clause 7.12, non-capital costs for any year of the period from 1 January 2005 until 31 December 2010 do not include the costs associated with:

(i) Gas used as compressor fuel during the year;

(ii) Gas used as fuel in gas engine alternators and heaters;

(iii) Gas which is vented during maintenance activities;

(iv) Gas which is lost from the DBNGP; or

(v) Charges levied on Operator pursuant to the *Economic Regulation Authority (Gas Pipelines Access Funding) Regulations 2003*.

768. DBP has proposed that amounts be included in total revenue for the 2011 to 2015 access arrangement period under the incentive mechanism of the current arrangement. These amounts are $10.470 million in 2011 and $10,215 million in 2012 (in dollar values of 2010).

769. The proposed revised access arrangement does not include an incentive mechanism. DBP has not provided any reasons for removing the incentive mechanism from the access arrangement.

Submissions

770. Two parties that made submissions on the proposed revised access arrangement expressed concern over the lack of inclusion of an incentive mechanism in the proposed revised access arrangement indicating that this will lower the incentive upon DBP to reduce costs during the 2011 to 2015 period.[406]

Considerations of the Authority

771. The Authority has given consideration to two matters in relation to an incentive mechanism under the access arrangement:

- the determination of the amounts proposed by DBP to be added to total revenue under the incentive mechanism of the current access arrangement; and
- the proposal by DBP to not include an incentive mechanism in the access arrangement for the 2011 to 2015 access arrangement period.

Additions to Total Revenue

772. DBP's proposed amounts to be added to total revenue under the incentive mechanism of the current access arrangement arise from differences between forecast and operating expenditure. DBP's stated values of operating and forecast operating expenditure applied in the incentive mechanism are shown in Table 47.

Table 47 Values of forecast and actual operating expenditure for 2005 to 2009 applied by DBP to the incentive mechanism for the 2005 to 2010 access arrangement period (nominal $ million)[407]

Year	2005	2006	2007	2008	2009
Forecast operating expenditure	41.728	41.121	55.578	54.874	53.181
Actual operating expenditure	36.270	39.410	44.400	52.460	65.597
Difference (actual – forecast)	**5.458**	**1.711**	**11.178**	**2.414**	**-12.416**

406 Newgen Power, 9 July 2010; Wesfarmers Chemicals, Energy & Fertilisers, 9 July 2010.

407 DBP proposed tariff model of 5 July 2010.

773. The Authority has reproduced DBP's determination of the amounts to be added to total revenue under the incentive mechanism of the current access arrangement. The amounts have been determined in accordance with the incentive mechanism as specified under the access arrangement except that:

- the CPI values applied by DBP are December quarter CPI values, rather than September quarter values as required under the incentive mechanism; and
- DBP has not excluded from the forecast and actual operating expenditure the forecast and actual amounts of charges levied on DBP pursuant to the *Economic Regulation Authority (Gas Pipelines Access Funding) Regulations 2003*.

774. The Authority also observes that the CPI values applied by DBP are from the "all-groups – Perth" CPI.

775. On the matter of the CPI values applied in the calculations of the incentive mechanism, the Authority has re-calculated amounts under the incentive mechanism applying September quarter CPI values from the "all-groups eight capital cities" CPI. This results in lower values of amounts to be added to total revenue of $9.932 million in each of 2011 and 2012, compared with the values proposed by DBP of $10.470 million in 2011 and $10,215 million in 2012 (in dollar values of 2010).

776. On the matter of exclusion from the forecast and actual operating expenditure of the forecast and actual amounts of charges levied on DBP pursuant to the *Economic Regulation Authority (Gas Pipelines Access Funding) Regulations 2003*, the Authority does not have information that would enable correction of the forecast values of operating expenditure for the amounts of charges included in this forecast. The amounts of these charges allowed for in the forecast of operating expenditure for the 2005 to 2010 access arrangement period were not separately specified in documentation for the proposed revisions to the access arrangement of 2005.

777. A further matter of relevance to the determination of carryover amounts under the incentive mechanism is that the Authority is not satisfied that DBP's determination of carryover values under the incentive mechanism is based on accurate and verified records of actual operating expenditure in the 2005 to 2011 access arrangement period. There are significant discrepancies in statements of operating expenditure provided to the Authority, in particular values stated by DBP in the revised access arrangement information and values provided by DBP to the Authority's expert technical advisor in more detailed breakdowns of operating costs for 2008 and 2009 (Table 48).

Table 48 Values of actual operating expenditure (net of fuel gas costs) for 2005 to 2009 supplied by DBP in supporting documents for the proposed revised access arrangement (nominal $ million)

Year	2005	2006	2007	2008	2009
DBP tariff model and access arrangement information	36.270	39.410	44.400	52.460	65.597
Cost line-item breakdowns of operating expenditure[408]	Not provided	Not provided	Not provided	52.638	67.881

778. Taking into account the absence of verification of reported values of operating expenditure and deficiencies in DBP's calculation of amounts under the incentive mechanism, the Authority is not satisfied that the DBP's proposed increments to total revenue comply with the incentive mechanism. The Authority has therefore excluded the carryover amounts from the determination of total revenue for the 2011 to 2015 access arrangement period.

779. Before including any increment to total revenue under the incentive mechanism, the Authority would require verification of values and timing of actual operating expenditure by an independent audit and correction of calculations. The Authority will therefore require amendment of the proposed revised access arrangement to exclude the increments to total revenue under the incentive mechanism applying under the current access arrangement.

Required Amendment 9

The proposed revised access arrangement should be amended to exclude from total revenue the increment amounts determined under the incentive mechanism that applied in the 2005 to 2010 access arrangement period.

Incentive Mechanism for the 2011 to 2015 Access Arrangement Period

780. The Authority considered whether it should require that the access arrangement for the 2011 to 2015 access arrangement period include an incentive mechanism to encourage efficiency in the provision of services by DBP.

781. Rule 98 of the NGR provides that a full access arrangement may include (and the Authority may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.

782. The Authority considers that the roles of an incentive mechanism in an access arrangement include the following:

- to promote incentives for the service provider to achieve efficiency gains to the ultimate benefit of pipeline users;
- to ensure that there is a continuous incentive to achieve efficiency gains, and in particular to ensure that there are incentives for efficiency gains in later years of an access arrangement period; and

408 Halcrow & Zincara, p158.

- to increase the confidence that the Authority can place on values of actual costs as an indicator of efficient costs and a benchmark to apply in assessment of cost forecasts, particularly actual costs in the later years of an access arrangement period.

783. In considering the roles and benefits of an incentive mechanism, the Authority recognises that an incentive mechanism involving the carry-over of benefits of efficiency gains from one access arrangement period to the next may create undesirable incentives for the service provider, such as:

- incentives to inefficiently shift costs across years (particularly to later years in the access arrangement period) to create a benefit for the service provider under the incentive mechanism without there being a sustained reduction in costs that will benefit pipeline users; and

- where an incentive mechanism is applied only to operating expenditure, incentives to inefficiently substitute capital expenditure for operating expenditure.

784. Under the incentive mechanism applying under the access arrangement for the 2005 to 2010 access arrangement period, the Authority is concerned that DBP has had an incentive to shift costs from early to later in the access arrangement period and that this may have been at least partly responsible for the trend of increasing operating costs over the period. In this case, the potential outworking of the incentive mechanism is a benefit to DBP of approximately $20 million, but there is no obvious benefit to users of the DBNGP through sustained efficiency gains in operating costs. Moreover, the incentive mechanism has not served to increase the confidence of the Authority in interpreting the actual costs for the latter years of this period as a benchmark of efficient costs.

785. Taking into account the undesirable properties of the incentive mechanism under the access arrangement for the 2005 to 2010 access arrangement period, the Authority will not impose a requirement to maintain this incentive mechanism in the access arrangement for the 2011 to 2015 access arrangement period.

786. The Authority has given consideration to whether the incentive mechanism of the current access arrangement can be modified to negate the potential for undesirable incentives to be created by the mechanism. The Authority is of the view that it is not practical to impose an incentive mechanism that provides the necessary protections against adverse incentives and therefore will not require the proposed revised access arrangement to be amended to include an incentive mechanism.

Operating Expenditure

Regulatory Requirements

787. Rule 91 of the NGR provides that operating expenditure must be 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 of delivering pipeline services.

788. Rule 71 of the NGR is relevant to the Authority's consideration of forecast operating expenditure against the requirements of rule 91, particularly in considering whether actual operating expenditure for the 2005 to 2010 access arrangement period provides a benchmark of an efficient level of operating expenditure. Rule 71 states that:

> 71 Assessment of compliance
>
> (1) In determining whether capital or operating expenditure is efficient and complies with other criteria prescribed by these rules, the [Economic Regulation Authority] may, without embarking on a detailed investigation, infer compliance from the operation of an incentive mechanism or on any other basis the [Economic Regulation Authority] considers appropriate.
>
> (2) The [Economic Regulation Authority] must, however, consider and give appropriate weight to, submissions and comments received when the question whether a relevant access arrangement proposal should be approved is submitted for public consultation.

DBP's Proposed Revisions

Operating Expenditure in the 2005 to 2010 Access Arrangement Period

789. Section 4 of the revised access arrangement information sets out DBP's stated actual operating expenditure for the 2005 to 2010 access arrangement period, as indicated in Table 49 (dollar values of 31 December 2010).

Table 49 DBP's stated actual operating expenditure for the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[409]

Year ending 31 December	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 F/cast
Other operating expenditure	41.906	44.099	48.255	54.988	67.338	66.418
Fuel gas	27.868	23.980	33.246	15.880	19.114	21.510
Total	**69.773**	**68.078**	**81.501**	**70.868**	**86.452**	**87.928**

Forecast Operating Expenditure in the 2011 to 2015 Access Arrangement Period

790. Section 9 of the revised access arrangement information sets out DBP's forecast operating expenditure for the 2011 to 2015 access arrangement period, which comprises six categories of expenditure: wages and salaries, non-field expenditure, field expenditure, government charges, reactive maintenance and fuel gas. Values are also provided in DBP's financial model, which are shown in Table 50 (expressed in dollar values of 31 December 2010).

409 DBP, 1 April 2010, Revised access arrangement information, sections 4, 9.

Table 50 DBP's forecast operating expenditure for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[410]

Year ending 31 December	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Wages & Salaries	26.408	26.924	27.449	27.985	28.531
Non-Field Expense	18.000	18.000	18.000	18.557	18.557
Field Expense	19.869	19.870	19.871	19.870	19.870
Government Charges	19.574	20.274	20.502	21.084	21.643
Fuel gas	20.427	21.585	21.495	23.679	24.118
Total	**104.278**	**106.653**	**107.317**	**111.175**	**112.719**

Substantiating Information for Forecast Operating Expenditure

791. DBP indicates in the revised access arrangement information that forecast operating expenditure for recurrent items has been derived from its annual internal business (planning and budgeting) processes. DBP also indicates that the forecast for fuel gas expenditure is based on the gas prices that DBP pays for the use of system use gas and the quantity of system use gas required.

792. DBP states in the revised access arrangement information that the actual operating expenditure incurred in the 2005 to 2010 access arrangement period does not inform consideration of the forecast operating expenditure:

> As at the commencement of the [2011 to 2015] access arrangement period, [the DBNGP] has 50% more compressor units than 2005 and has been almost 85% looped since 2005. Accordingly, the Operating Expenditure required to operate the DBNGP as it is presently configured is very different to that required in 2005, thus making the reference to historical Operating Expenditure inappropriate.[411]

793. DBP has not provided the Authority with information to verify actual operating expenditure in the 2005 to 2010 access arrangement period.

794. In support of its forecasts of operating expenditure, DBP has provided the Authority with further information in a confidential supporting submission.[412]

Submissions

795. Parties that made submissions to the Authority on the proposed revised access arrangement have raised several concerns with the forecast of operating expenditure for the 2011 to 2015 access arrangement period, as follows.

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410 DBP, 1 April 2010, revised access arrangement information sections 4, 9.

411 DBP, 1 April 2010, revised access arrangement information, section 4.2 and 4.3, p.7.

412 DBP, 14 April 2010, Confidential supporting submission #12: Justification of operating expenditure. A public version of this submission is available to interested parties.

- Concern is expressed over the dramatic increase in DBP operating expenditure (excluding fuel costs) between the 2010 forecast and the 2011 forecast and between the 2010 actual costs and 2011 forecast.[413] [414]
- Information provided by DBP does not provide sufficient detail or clarity to be able to assess the efficiency of the proposed non-fuel gas operating cost allowance and that there is a very real possibility that the proposed operating cost allowance is significantly in excess of those that an efficient operator would incur.[415] DBP provides very little explanation or information as to the break-down of specific items of operating expenditure during the 2005- 2010 access arrangement period, with expenditure categorised as either "fuel gas" or "other". The lack of detail makes it very difficult to assess the reasonableness of differences between actual and forecast expenditure, which in turn makes assessment of the reasonableness of the forecast operating expenditure equally difficult.[416]
- DBP states in its submissions that due to the changed configuration of the DBNGP since 2005 it is inappropriate to refer to historical expenditure. This argument is incorrect, and that historical expenditure, particularly from 2008 to 2010 is very relevant to an assessment of forecast expenditure for the period 2011 to 2015.[417]
- DBP's claim that its forecast operating expenditure complies with NGR 91(1) does not appear to be supported by information contained in its proposed revised AAI or its submissions do not appear to be supported by: independent analysis or review of its actual or forecast operating expenditure; or any benchmarking comparison to other natural gas transmission businesses.[418]
- It may not be appropriate to include a forecast of costs for compliance with a CPRS given that the Commonwealth Government has expressed its intention to delay introduction of the CPRS legislation until after 2012, making it unlikely that any CPRS will have a significant impact during the 2011 to 2015 period.[419]
- It is not clear whether fuel gas provided by shippers on the DBNGP has been taken into account in the forecast expenditure on fuel gas.

413 Newgen Power, 9 July 2010, ERM Power Pty Ltd, 7 July 2010; Synergy, 9 July 2010.

414 Alinta Pty Limited, 9 July 2010.

415 Newgen Power, 9 July 2010, ERM Power Pty Ltd, 7 July 2010.

416 Verve Energy, 9 July 2010; Synergy, 9 July 2010.

417 Verve Energy, 9 July 2010; Synergy, 9 July 2010.

418 Alinta Pty Limited, 9 July 2010.

419 Wesfarmers Chemical, Energy & Fertilisers, 9 July 2010; Verve Energy, 9 July 2010.

- The Authority should give attention to the forecast price of fuel gas, taking into account that, in 2009, DBP accepted a request by its fuel gas supplier to pay a price above its contracted price for future fuel gas supplies and it is not reasonable for this voluntary increase in fuel gas prices to be passed through as operating expenditure (which contributes to an increased reference tariff).[420] DBP has not provided any information as to either the forecast volume of fuel gas it expects the DBNGP to require each year in the period 2011-2015, nor the price at which it has assumed it will be able to obtain this volume of fuel gas, and the absence or suppression of this information means that users and prospective users cannot reasonably be expected to form a view on whether the forecast complies with NGR 91(1) and NGR 74(2).[421]
- There appears to be no discussion of DBP's decision in early 2009 to bring back in-house a significant proportion of the operating and maintenance services that were then contracted out to Westnet Energy Services Pty Ltd. This decision appears to be very relevant to both DBP's actual operating expenditure for the period 2005-2010 and its forecast operating expenditure for the period 2011-2015.[422]

796. These matters are addressed by the Authority below.

Considerations of the Authority

Approach to the Assessment of Forecast Operating Expenditure

797. The starting point for the Authority in considering the forecast of operating expenditure is the levels of expenditure in the 2005 to 2010 access arrangement period.

798. The Authority does not accept DBP's contention that referencing historical operating expenditure is inappropriate. Rather, the Authority considers that the scheme of incentive regulation established by the NGR favours this approach. The scheme of regulation provides incentives for cost efficiency by a pipeline service provider by allowing the service provider to capture benefits of outperforming forecasts of costs. These incentives allow a regulator to place considerable weight on actual costs as an indicator of an efficient level of costs.

799. While the Authority accepts that there has been substantial expansion of the DBNGP during the 2005 to 2010 access arrangement period and that this expansion will affect operating activities and costs, the Authority considers that these activities and costs should be able to be readily taken into account in justifying changes in operating expenditure between the actual costs of the 2005 to 2010 access arrangement period and the forecast costs of the 2011 to 2015 access arrangement period.

800. The process adopted by the Authority in considering the forecast of operating expenditure has been to:

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420 Wesfarmers Chemical, Energy & Fertilisers, 9 July 2010.

421 Alinta Pty Limited, 9 July 2010.

422 Alinta Pty Limited, 9 July 2010.

- assess whether the actual operating expenditure in the 2005 to 2010 access arrangement period is consistent with the criteria of rule 91 of the NGR, hereafter referred to the prudence and efficiency criteria of rule 91; and
- assess whether DBP has provided adequate justification for forecast trends and step changes in levels of capital expenditure over the term of the 2011 to 2015 access arrangement period.

Prudence and Efficiency of Operating Expenditure in the 2005 to 2010 Access Arrangement Period

801. The Authority has considered whether the actual operating expenditure for the 2005 to 2010 arrangement period is consistent with the criteria governing operating expenditure set out in rule 91 of the NGR.

802. Neither the revised access arrangement information nor DBP's submission in support of the forecast of operating expenditure address the efficiency of operating expenditure in the 2005 to 2010 access arrangement period.

803. In the absence of supporting information from DBP, the Authority has assessed the consistency of operating expenditure in the 2005 to 2010 access arrangement with the prudence and efficiency criteria of rule 91 of the NGR by:

    - consideration of the commercial incentives of DBP to be prudent and efficient in operating activities and expenditure;
    - examination of differences between forecast and actual operating expenditure in the access arrangement period and reasons for these differences; and
    - examination of reasons for some large increases in some cost line items of operating expenditure.

804. In undertaking this assessment, the Authority has relied on advice of expert engineering advisors.

805. The Authority accepts that DBP faces commercial incentives for efficiency in operating expenditure. Under the regulatory regime established by the NGL and NGR, a service provider has some commercial incentive for prudence and efficiency in operating expenditure. This incentive arises from:

    - the ability of the service provider to retain the benefit of out-performing forecasts of operating expenditure that are taken into account in the determination of reference tariffs (at least to the extent that users of the pipeline are paying tariffs at the level of the reference tariffs);
    - the inability of the service provider to recover, through regulated tariffs, any operating expenditure in excess of the forecast expenditure (again, at least to the extent that users of the pipeline are paying tariffs at the level of the reference tariffs).

806. With users of the DBNGP not currently paying tariffs at the level of the reference tariff established under the access arrangement,[423] these elements of the commercial incentive for prudence and efficiency in operating expenditure do not directly apply. However, notwithstanding that users of the DBNGP do not currently pay a reference tariff, the terms of the SSC for the provision of pipeline services would provide commercial incentives for prudence and efficiency in operating expenditure. The Authority considers that these incentives operate similarly to the incentives that exist under the regulatory regime established by the NGL and NGR.

807. Under the SSCs with users, tariffs for gas transmission have been established independently of the regulated tariffs or price controls established under the access arrangement and will remain so until at least 2016.[424] The tariffs established under the SSCs are fixed with the exception of:

- escalation for inflation;[425]
- changes in taxation that are able to be passed through in changes to tariffs;[426] and
- adjustments (increases or decreases) in respect of certain amounts of expansion capital expenditure, calculated as a rate of return on a difference between actual expansion costs and certain benchmarks of expansion costs specified in the SSC.[427]

808. There is no provision under the SSC for tariffs to vary to recover amounts of additional operating expenditure, nor to vary if DBP achieves efficiencies and reductions in operating expenditure.

809. The Authority considers that the nature of the tariff arrangements under the SSCs provide strong commercial incentives for DBP to be prudent and efficient in its operating expenditure for reasons that DBP would otherwise be exposed to cost overruns on operating activities, as well as DBP's ability to benefit from cost reductions.

810. A comparison of forecast and actual operating expenditure for the 2005 to 2010 access arrangement period (Table 51) indicates:

- "other" operating expenditure over the period exceeding the forecast by approximately $7.7 million (dollar values of 31 December 2010) or 2.5 per cent of the forecast, with actual expenditure being less than forecast at the beginning of the period but substantially greater than forecast towards the end of the period; and
- costs of fuel gas being substantially less than forecast, by approximately $40.4 million or 22.2 per cent of the forecast.

423 DBP, Standard Shipper Contract clause 20.5(d).
424 DBP, Standard Shipper Contract clause 20.5(d).
425 DBP, Standard Shipper Contract clause 20.5(c).
426 DBP, Standard Shipper Contract clause 20.7.
427 DBP, Standard Shipper Contract clause 20.8.

Table 51 Comparison of forecast and DBP's stated actual operating expenditure for the 2005 to 2010 access arrangement period (real $million at 31 December 2010)[428]

Year ending 31 December	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 F/cast
Other operating expenditure						
Forecast	47.664	45.008	59.047	56.194	53.338	54.149
Actual	41.906	44.099	48.255	54.988	67.338	66.418
Difference	**-5.759**	**-0.909**	**-10.792**	**-1.206**	**14.001**	**12.270**
Fuel gas						
Forecast	22.949	22.951	32.952	34.436	34.396	34.421
Actual	27.868	23.980	33.246	15.880	19.114	21.510
Difference	**4.919**	**1.028**	**0.294**	**-18.556**	**-15.282**	**-12.911**

811. While requests were made to DBP to provide explain the differences between forecast and actual operating expenditure, no explanation was forthcoming.[429] The Authority's advice from its expert engineering advisor is that DBP does not currently adopt activity based costing, which would provide greater clarity of the allocation of DBP's operating expenditure to different activities and drivers, and there is no documentation from DBP to link movements in historical or forecast expenditure against specific drivers.[430]

812. The Authority has been particularly concerned to examine the reasons for substantial excesses of actual non-capital costs other than fuel gas over forecasts for these costs in 2009 and 2010. The Authority is less concerned about differences between forecast and actual fuel costs, due to the actual costs being less than forecast and the expansions and contracted capacity of the pipeline being different to those projected at the time the forecasts were made (as addressed at paragraphs 200 to 202 of this draft decision).

813. DBP has provided information on a breakdown of actual operating expenditure for the years 2008 to 2010 (Table 52). This information provides some basis to examine the reasons for the excess of actual over forecast costs in 2009 and 2010 for cost items other than fuel gas.

814. The table below provides the Authority's analysis of this breakdown of expenditure.

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428 Forecast values from Appendix 2 of the Authority's Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 2 November 2005. Values converted to real dollar values of 31 December 2010 using the inflation factors of the Authority.

429 Halcrow & Zincara, p. 156.

430 Halcrow & Zincara, p. 153.

Table 52 Breakdown of DBP's actual operating expenditure for the years 2008 to 2010 in the 2005 to 2010 access arrangement period (real $ million at 31 December 2010)[431]

Year ending 31 December	2008 Actual	2009 Actual	2010 F/cast
Recurrent costs			
Wages and salaries - salaries	22.442	22.815	24.471
Wages and salaries - contractors	2.679	2.644	1.358
Non-field expense - consulting	3.993	6.916	6.649
Non-field expense - entertainment expenses	0.084	0.129	0.189
Non-field expense - IT expenses	1.136	5.696	5.742
Non-field expenses - insurance costs	4.036	4.249	4.520
Field expense - motor vehicle expenses	0.840	1.344	0.937
Non-field expense - office and administration expenses	0.915	1.123	0.915
Field expense - repairs and maintenance expenses	7.073	7.165	5.615
Field expense - training & development expenses	0.858	0.918	1.177
Field expense - travel & accommodation expenses	2.674	2.476	2.113
Government charges – utilities, rates & taxes	5.963	10.813	11.066
Government charges - CPRS costs			
Non-field expense - self insurance			
Non-field expense - miscellaneous	0.174	1.052	0.405
Total recurrent costs	**52.867**	**67.341**	**65.157**
Non-recurrent costs			
Reactive maintenance			
Operating Services Agreement charges	2.310	2.345	
Field Expense - compressor overhauls			
Non-field expense - regulatory expenses			
Fuel gas	15.878	19.118	21.510
Total non-recurrent costs	**18.188**	**21.463**	**21.510**
TOTAL	**67.786**	**86.505**	**86.667**

815. The Authority observes that there are differences in the records of actual operating expenditure between the total values as indicated by DBP in the revised access arrangement information (Table 49 at paragraph 789 of this draft decision) and the breakdown of expenditure as shown in Table 52. DBP has not explained these differences. In considering actual capital expenditure in the 2005 to 2010 access arrangement period, the Authority has relied on the values provided in the breakdown and as shown in Table 52.

431 Halcrow & Zincara, p 158.

816. The breakdown of actual operating expenditure shows that the large increases in operating expenditure from 2008 to 2009 (by approximately $15 million per annum) for cost items other than fuel gas arose primarily from "step change" increases in costs of consulting, IT expenses, and government charges and utilities. There is also a significant decrease in costs from 2009 to 2010 of approximately $2.3 million with cessation of charges payable in relation to the Operating Services Agreement.

817. Consultancy costs appear to relate to costs of a range of outsourced services. An increase in costs by approximately $3 million (in dollar values of 31 December 2010) occurred between 2008 and 2009 to a total of $6.9 million (in dollar values of 31 December 2010), which was maintained into 2010. Advice to the Authority indicates that up to about $1 million of this is explained by increases in costs related to the outsourcing of maintenance of the microwave communications network after the termination of an agreement with Western Power under which costs for maintenance of this network were shared.[432] The Authority's expert engineering advisor concluded that insufficient information was provided by DBP for breakdowns of expenditure for the 2008 to 2011 years to enable a determination of whether the consultancy expenditure over and above that for maintenance of the microwave communications network is consistent with the prudence and efficiency criteria of rule 91.[433] The Authority therefore does not have any information to justify approximately $2 million of the increase in costs from 2008 to 2009.

818. IT expenses have been indicated by DBP to comprise costs incurred under an IT outsourcing agreement with WestNet Energy Services. There occurred an increase in costs by approximately $4.5 million (in dollar values of 31 December 2010) between 2008 and 2009, which is projected to be maintained into 2010. Advice to the Authority indicates that this increase in costs resulted from a review of costs to WestNet Energy Services of providing IT services, with this review being coincident with the 2009 revision and amendment of the Operating Services Agreement with Alinta Asset Management and subsequently with WestNet Energy Services (as described in paragraph 231 and following of this draft decision). In particular, increases in charges paid to WestNet Energy Services were necessary to allow WestNet Energy Services to recover labour costs and capital costs of IT assets to a total of about $4.8 million per annum.[434] Increases in charges have also been attributed by DBP to a loss of economies of scale in provision of IT services by Alinta Asset Management as a result of the disaggregation of Alinta,[435] IT requirements of expansion projects and increases in numbers of employees, additional software licence fees and IT systems for vehicle tracking and a driver drowsiness alert system.[436,437]

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432 Halcrow & Zincara, pp. 181, 182 citing DBP, DBNGP Revised Access Arrangement Proposal Submission: Submission 12:Justification of Operating Expenditure, 14 April 2010, p. 13

433 Halcrow & Zincara, p. 180.

434 Halcrow & Zincara, p. 187 citing DBP, Attachment 6.1a (Table 2) to Submission 23: Response to Halcrow Pacific Issues Report/Request of Information, dated 21 July 2010.

435 Halcrow & Zincara, p. 187, citing DBP, Submission 12: Justification of Operating Expenditure, 14 April 2010, p. 14.

436 Halcrow & Zincara, pp. 187, 188, citing DBP, Submission 23: Response to Halcrow Pacific Issues Report/Request of Information, dated 21 July 2010, page 20; and DBP, Attachment 6.1a (Table 2) to Submission 23: Response to Halcrow Pacific Issues Report/Request of Information, dated 21 July 2010.

437 Halcrow & Zincara, p. 188.

819. Of these stated reasons for increases in IT expenses, the Authority observes that the increases in costs under outsourcing arrangements with WestNet Energy Services conflicts with statements made by DBP at the time of revision and amendment of the Operating Services Agreement that "with the exception of the anticipated efficiencies, there will be no material change to DBP's cost base as a result of the changes."[438]

820. The Authority is satisfied that some of the increase in IT expenses from 2008 to 2009 is likely to be consistent with the prudence and efficiency criteria of rule 91 of the NGR. However, the Authority is concerned that the whole of the increase in charges for IT services provided by WestNet Energy Services under the revised and amended Operating Services Agreement may not be consistent with these criteria. In the absence of sufficient relevant evidence, the Authority is concerned that these charges may have been influenced by a negotiation of payments to WestNet Energy Services that occurred as part of the unwinding of the original Operating Services Agreement and may not represent genuine costs.

821. Costs in the category of "Government charges – utilities rates & taxes" increased by approximately $5 million (in dollar values of 31 December 2010) between 2008 and 2009, with this increase maintained into 2010. Advice to the Authority indicates that this increase is explained by increases in access fees for the DBNGP land corridor (payable to the Western Australian Department of Planning and Infrastructure) and increases in rent and accommodation expenses after expiration of a "rent-free" period for Perth office accommodation. The Authority is satisfied with this justification and that the increases in costs are likely to be consistent with the prudence and efficiency criteria of rule 91.[439]

822. Taking into account the commercial incentives faced by DBP for efficiencies in operating expenditure, the comparison of forecast and actual operating expenditure and the explanatory information made available by DBP for large increases in some cost line items of operating expenditure, the Authority considers that a benchmark of operating expenditure that is consistent with the prudence and efficiency requirements of rule 91 is provided by the actual operating expenditure in 2009 adjusted to exclude:

- $2 million in consulting expenses;
- $3 million in IT expenses; and
- $2.341 million in charges (in 2009) under the Operating Services Agreement.

Prudence and Efficiency of Forecast Operating Expenditure in the 2011 to 2015 Access Arrangement Period

823. The Authority has assessed the forecast of operating expenditure for the 2011 to 2015 access arrangement period by assessment of step changes and trends in cost line items from the benchmark of efficient and prudent costs for 2009.

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438 Halcrow & Zincara, p. 187, citing DBP, Media Statement, Monday 9 February 2009 (Attachment to ASX announcement).

439 Halcrow & Zincara, pp. 206, 207, citing Department for Planning and Infrastructure, Letter *Dampier to Bunbury Gas Pipeline (DBNGP) Corridor – Re-evaluation of Access Right Charges*, dated 16 October 2008.

824. The benchmark of costs in 2009 and forecast costs for 2010 and the 2011 to 2015 access arrangement period are shown in Table 53.

Table 53 Benchmarks of operating expenditure for 2009 and forecast operating expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
Wages and salaries - salaries	22.815	24.471	25.017	25.505	26.003	26.510	27.028
Wages and salaries - contractors	2.644	1.358	1.392	1.419	1.446	1.474	1.503
Non-field expense - consulting	4.916	6.649	5.801	5.802	5.802	5.802	5.802
Non-field expense - entertainment expenses	0.129	0.189	0.188	0.189	0.189	0.189	0.188
Non-field expense - IT expenses	2.696	5.742	5.759	5.759	5.759	5.759	5.759
Non-field expenses - insurance costs	4.249	4.520	4.726	4.726	4.726	4.726	4.726
Field expense - motor vehicle expenses	1.344	0.937	0.937	0.937	0.938	0.938	0.938
Non-field expense - office and administration expenses	1.123	0.915	0.918	0.918	0.918	0.919	0.918
Field expense - repairs and maintenance expenses	7.165	5.615	5.645	5.646	5.645	5.646	5.646
Field expense - training & development expenses	0.918	1.177	1.193	1.194	1.193	1.193	1.193
Field expense - travel & accommodation expenses	2.476	2.113	2.133	2.133	2.133	2.133	2.133
Government charges – utilities, rates & taxes	10.813	11.066	10.974	10.974	10.974	10.974	10.974
Government charges - CPRS costs			8.600	9.300	9.528	10.111	10.669
Non-field expense - self insurance			0.228	0.228	0.228	0.228	0.227
Non-field expense - miscellaneous	1.052	0.405	0.330	0.330	0.330	0.330	0.330
Total recurrent costs	**62.341**	**65.157**	**73.841**	**75.059**	**75.812**	**76.930**	**78.035**
Non-recurrent costs							
Reactive maintenance			1.172	1.172	1.172	1.172	1.172
OSA Charges			0.000	0.000	0.000	0.000	0.000
Field Expense - compressor overhauls			8.788	8.788	8.789	8.788	8.788
Non-field expense - regulatory expenses			0.049	0.049	0.048	0.606	0.606
Fuel gas			20.427	21.585	21.495	23.679	24.118
Total non-recurrent costs	**19.118**	**21.510**	**31.169**	**33.163**	**33.896**	**37.766**	**39.206**
Total	**81.459**	**86.667**	**105.011**	**108.222**	**109.709**	**114.696**	**117.241**

825. The forecast of operating expenditure for the 2011 to 2015 access arrangement period has been considered by the Authority by assessment of each cost line item, as follows.

Wages & Salaries

826. The cost category of wages and salaries comprises remuneration payments to employees and contractors.

827. The benchmark costs of wages and salaries for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 54.

Table 54 Benchmarks of wages and salaries expenditure for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
Wages and salaries - salaries	22.815	24.471	25.017	25.505	26.003	26.510	27.028
Per cent change		7.3	2.2	2.0	2.0	2.0	2.0
Wages and salaries - contractors	2.644	1.358	1.392	1.419	1.446	1.474	1.503
Per cent change		-48.6	2.5	1.9	2.0	1.9	1.9
Total	25.459	25.829	26.408	26.924	27.449	27.985	28.531
Per cent change		1.5	2.2	2.0	2.0	2.0	2.0

828. DBP has forecast a shift in wages and salaries cost from contractors to employees between 2009 and 2010, which reflects a transfer of activities and personnel from WestNet Energy Services to DBP. In total, the forecast of wages and salaries costs embodies a real rate of increase of 2 per cent per annum (corresponding to a nominal rate of increase of 4.5 per cent per annum) which DBP indicates to be an assumed rate of increase in labour rates. DBP further indicates that this assumption reflects historical rates of growth in average weekly earnings and expectations of upward pressure on wage rates in the Western Australian resources sector.[440]

829. Information provided by DBP to the Authority's technical advisor indicates an expectation by DBP of increasing staff numbers in operational roles from 150.5 full-time equivalents to 170.4 full-time equivalents in 2011.[441] It is not clear how this increase in staff numbers is reflected in the forecast of wages and salaries costs, which DBP states to be based only on the forecast rate of growth of average weekly earnings. With an increase in staff numbers, the implicit assumption of growth in wage and salary rates would be less than the stated assumption of 2 per cent per annum real.

440 DBP, 14 April 2010, Submission #12 pp 15, 16.

441 Halcrow & Zincara, p. 169.

830. The Authority observes that DBP's forecast of the rate of growth in average weekly earnings of 4.5 per cent per annum nominal is lower than recent rates of earnings growth in Western Australia of 5.3 per cent for the year to August 2010 and 6.6 per cent for the five years to August 2010.[442]

831. On the basis of the forecast rate of growth in total wages and salaries costs of less than recent rates of growth in Western Australian average weekly earnings, the Authority is satisfied that the forecast of these costs is consistent with the prudence and efficiency criteria of rule 91.

Consultancy

832. The cost category of consulting comprises costs of a range of outsourced services.

833. The benchmark cost of consultancy for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 55. As indicated above, the benchmark for 2009 comprises the stated costs of DBP for these years less $2 million in each year.

Table 55 Benchmarks of consultancy expenditure for 2009 and 2010 and forecast expenditure for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
Consultancy	4.916	6.649	5.801	5.802	5.802	5.802	5.802
Per cent change		35.3	-12.7	0.0	0.0	0.0	0.0

834. DBP has forecast costs for consultancy that are constant in real terms over the 2011 to 2015 access arrangement period at an amount of $5.802 million (in dollar values of 31 December 2010), which is approximately $1 million less than DBP's stated costs for 2009 and 2010, but $1 million greater than the benchmark for 2009 determined by the Authority to be consistent with the prudence and efficiency criteria of rule 91.

835. Just as DBP has not provided sufficient information to support the increases in consultancy costs from 2008 to 2009, DBP has not provided information to justify the ongoing high levels of consultancy costs in 2010 to 2015. In the absence of justifying information, the Authority is not satisfied that the forecast level of these costs is consistent with the prudence and efficiency criteria of rule 91.

836. The Authority will require amendment of the forecast of operating expenditure to reflect a level of consultancy costs in each year of the 2011 to 2015 access arrangement period of $4.916 million, equal to the benchmark cost established by the Authority for 2009.

[442] Australian Bureau of Statistics, 6302.0 - Average Weekly Earnings, Australia, Aug 2010, Table 11E (Full time adult ordinary time earnings).

Entertainment Expenses

837. The benchmark cost of entertainment expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 56.

Table 56 Benchmark of entertainment expenditure for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
Entertainment expenses	0.129	0.189	0.188	0.189	0.189	0.189	0.188
Per cent change		46.1	-0.3	0.1	0.0	0.0	-0.1

838. DBP has forecast costs for entertainment expenses that are an increase by 46 per cent over actual costs in 2009, but constant in real terms over the period 2010 to 2015.

839. DBP has not provided information to explain or justify the increase in costs between 2009 and 2010.

840. In the absence of supporting information for the increase in costs from 2009 to 2010, the Authority is not satisfied that the forecast costs for 2011 to 2015 are consistent with the prudence and efficiency requirement of rule 91.

841. The Authority will require amendment of the forecast of operating expenditure to reflect a level of entertainment costs in each year of the 2011 to 2015 access arrangement period of $0.129 million, equal to the benchmark cost established by the Authority for 2009.

IT Expenses

842. The benchmark cost of IT expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 57.

Table 57 Benchmark of IT expenditure for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
IT expenses	2.696	5.742	5.759	5.759	5.759	5.759	5.759
Per cent change		113.0	0.3	0.0	0.0	0.0	0.0

843. DBP has forecast costs for IT expenses that are constant in real terms over the 2011 to 2015 access arrangement period at an amount of $5.759 million (in dollar values of 31 December 2010), which is approximately the same as DBP's stated costs for 2009 and 2010, but slightly more than $3 million greater than the benchmark for 2009 determined by the Authority to be consistent with the prudence and efficiency criteria of rule 91.

844. Just as DBP has not provided sufficient information to support the increases in IT expenses from 2008 to 2009, DBP has not provided information to justify the ongoing high levels of IT expenses in 2010 to 2015. In the absence of justifying information, the Authority is not satisfied that the forecast level of these costs is consistent with the prudence and efficiency criteria of rule 91.

845. The Authority will require amendment of the forecast of operating expenditure to reflect a level of IT expenses in each year of the 2011 to 2015 access arrangement period of $2.696 million (in dollar values of 31 December 2010), equal to the benchmark cost established by the Authority for 2009.

Insurance Costs

846. The benchmark cost of insurance for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 58.

Table 58 Benchmark of insurance expenditure for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs							
Insurance costs	4.249	4.520	4.726	4.726	4.726	4.726	4.726
Per cent change		6.4	4.6	0.0	0.0	0.0	0.0

847. Insurance costs include insurance premiums relating to property damage and business interruption insurance policies (these account for approximately 90 per cent of the costs) and Workcover premiums.

848. DBP has forecast costs for insurance that increase by 11.2 per cent over actual costs in 2009, but constant in real terms over the period 2011 to 2015. The increase in costs occurs as a 6.4 per cent increase from 2009 to 2010 and a further 4.6 per cent increase from 2010 to 2011.

849. The Authority's expert engineering advisor observes that the increase in insurance costs to 2011 is in proportion to the expansion of the assets of the DBNGP, as measured by the projected value of the DBNGP capital base and with insurance costs being an approximately constant value of 0.14 to 0.15 per cent of the capital base.[443]

850. On this basis, the Authority accepts that the forecast of insurance costs is consistent with the prudence and efficiency requirements of rule 91.

Motor Vehicle Expenses

851. The benchmark cost of motor vehicle expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 59.

443 Halcrow & Zincara, pp. 189, 190.

Table 59 Benchmark of motor vehicle expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Motor vehicle expenses	1.344	0.937	0.937	0.937	0.938	0.938	0.938
Per cent change		-30.3	0.0	0.0	0.0	0.0	0.0

852. Motor vehicle expenses are indicated by DBP to relate primarily to repairs and maintenance of vehicles and mobile plant, and fuel and oil costs. A forecast decline in costs from $1.344 million in 2009 to $0.938 million in each of the years 2010 to 2015 is indicated to be largely a result of a change in vehicle types. The Authority's expert engineering advisor is of the view that the costs are consistent with the prudence and efficiency requirement of rule 91.[444]

853. Taking into account the forecast decline in costs from the levels of 2009 and the expert advice provided to the Authority, the Authority is of the view that the forecast of motor vehicle expenses is consistent with the prudence and efficiency requirement of rule 91.

Office and Accommodation Expenses

854. The benchmark cost of office and accommodation expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 60.

Table 60 Benchmark of office and accommodation expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Office & accommodation expenses	1.123	0.915	0.918	0.918	0.918	0.919	0.918
Per cent change		-18.5	0.3	0.1	0.0	0.0	0.0

855. Office and accommodation expenses are indicated by DBP to be costs for a range of sundry and general expenditure items of which about two thirds is costs of a freight service provided by a contractor. DBP forecasts a decline in costs from $1.123 million in 2009 to approximately $0.918 million in each of the years 2010 to 2015. The Authority's expert engineering advisor is of the view that the costs are consistent with the prudence and efficiency requirement of rule 91.[445]

856. Taking into account the forecast decline in costs from the levels of 2009 and the expert advice provided to the Authority, the Authority is of the view that the forecast of office and accommodation expenses is consistent with the prudence and efficiency requirement of rule 91.

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444 Halcrow & Zincara, pp. 191, 192.

445 Halcrow & Zincara, pp. 191, 192.

Repairs and Maintenance Expenses and Reactive Maintenance

857. For the purposes of cost forecasts for the 2011 to 2015 access arrangement period, DBP has presented separate forecasts of "repairs and maintenance" as a recurrent cost and "reactive maintenance" as a non-recurrent cost. Actual and forecast costs for 2009 and 2010 are provided only as a combined total.

858. The benchmark cost of repairs and maintenance expenses and reactive maintenance for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 61.

Table 61 Benchmark of repairs & maintenance expenses and reactive maintenance for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Repairs & maintenance expenses							
Planned			5.645	5.646	5.645	5.646	5.646
Reactive			1.172	1.172	1.172	1.172	1.172
Total	7.165	5.615	6.817	6.817	6.817	6.818	6.818
Per cent change		-21.6	21.4	0.0	0.0	0.0	0.0

859. Repairs and maintenance expenses comprise costs for planned maintenance activities including the costs of tools and equipment purchase, furniture and fittings; hire/lease – other, cleaning & waste removal; security, gardening and plant maintenance; pest control; property repairs and maintenance; general materials; fuel and oils; repairs and maintenance office equipment, maintenance general; repairs and maintenance of equipment; and maintenance surveys. The forecast of these costs has been determined by DBP using a forecasting model that addresses maintenance activity for each maintained asset together with the budgeted cost of that activity.[446]

860. Reactive maintenance expenses comprise costs of unplanned maintenance, again excluding labour costs. The forecast of these costs has been derived as an average of actual costs over a three year period.[447]

861. DBP's stated actual costs for 2009 and forecast of costs for 2010 to 2015 indicate a decline in costs from $7.165 million in 2009 to $5.615 million in 2010 and then an increase to $6.811 million in each of the years 2011 to 2015 (dollar values of 31 December 2010). However, the actual costs for 2009 are indicated to include an amount of costs of $0.931 million (dollar values of 31 December 2010) arising from an adjustment to the value of inventories,[448] indicating that the benchmark cost in 2009 would be better stated as $6.234 million and the forecast costs for the 2011 to 2015 access arrangement period are 9.4 per cent greater than this benchmark.

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446 Halcrow & Zincara, p. 196.

447 Halcrow & Zincara, p. 201.

448 Halcrow & Zincara, pp. 194, 195.

862. The Authority's expert engineering advisor is of the view that the forecast of reactive maintenance costs is consistent with the prudence and efficiency requirement of rule 91 for reason of being determined as an average of three years of actual costs.

863. The Authority's expert engineering advisor is of the view that DBP has not adequately explained or justified increases in forecast repairs and maintenance expenses (planned maintenance) from the level of actual costs in 2009 (adjusted for the change in value of inventories) and forecast costs in 2010 and concludes that the increase in costs is not consistent with the prudence and efficiency requirement of rule 91.[449]

864. Taking into account the expert advice provided to the Authority, the Authority is of the view that the forecast of repairs and maintenance expenses is not consistent with the prudence and efficiency requirement of rule 91. The Authority will require amendment of the forecast of operating expenditure so that the total annual value of forecast costs for repairs and maintenance expenses and reactive maintenance in each year of the 2011 to 2015 access arrangement period is $6.234 million (in dollar values of 31 December 2010), equal to the actual cost of these activities in 2009 (after adjustment by $0.931 million for the change in value of inventories). For the purpose of expressing the forecast by cost line items, this will be allocated as annual values of $5.062 million for repairs and maintenance expenses and $1.172 million for reactive maintenance.

Training and Development Expenses

865. The benchmark cost of training and development expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 62.

Table 62 Benchmark of training and development expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Training & development expenses	0.918	1.177	1.193	1.194	1.193	1.193	1.193
Per cent change		28.3	1.4	0.0	0.0	0.0	0.0

866. Training and development expenditure includes staff training, subscriptions and memberships, and conferences and seminars. Costs are forecast to increase by 28.3 per cent in real terms from 2009 to 2010 and a further 1.4 per cent to 2011, but forecast at a constant annual value in real terms for the 2011 to 2015 access arrangement period.

449 Halcrow & Zincara, p. 198.

867. The Authority's expert engineering advisor indicates that the level of expenditure as a proportion of salary costs (2.6 per cent in 2009, increasing to 3.5 per cent) is approximately in line with a typical industry benchmark of 3 per cent. This advice also indicates that the increase in expenditure is probably accounted for by the development by DBP of training plans and a more structured approach to employee training.[450]

868. Taking into account the expert advice provided to the Authority, the Authority is of the view that the forecast of training and development expenses is consistent with the prudence and efficiency requirement of rule 91.

Travel and Accommodation Expenses

869. The benchmark cost of travel and accommodation expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 63.

Table 63 Benchmark of travel and accommodation expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Travel & accommodation expenses	2.476	2.113	2.133	2.133	2.133	2.133	2.133
Per cent change		-14.7	0.9	0.0	0.0	0.0	0.0

870. Travel and accommodation expenses are indicated by DBP to be costs for all interstate and intrastate accommodation, parking and taxi charges. DBP forecasts a decline in costs from $2.476 million in 2009 to $2.113 million in 2010, then a slight increase to $2.133 million in each of the years 2011 to 2015 (dollar values of 2010). DBP has indicated that the reduction of expenditure since 2008 is due to the internalisation of activities within DBP and within Western Australia.

871. The Authority's expert engineering advisor is of the view that the costs are consistent with the prudence and efficiency requirement of rule 91.[451]

872. Taking into account the forecast decline in costs from the levels of 2009 and the expert advice provided to the Authority, the Authority is of the view that the forecast of travel and accommodation expenses is consistent with the prudence and efficiency requirement of rule 91.

Utilities, Rates and Taxes

873. The benchmark cost of utilities, rates and taxes for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 64.

[450] Halcrow & Zincara, p. 203.

[451] Halcrow & Zincara, p. 205.

Table 64 Benchmark of utilities, rates and taxes expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Utilities, rates & taxes	10.813	11.066	10.974	10.974	10.974	10.974	10.974
Per cent change		2.3	-0.8	0.0	0.0	0.0	0.0

874. DBP forecasts a small increase in costs from 2009 to 2011 (approximately one per cent in real terms), with the value of costs being maintained at a constant level over the 2011 to 2015 access arrangement period.

875. The Authority has already examined the prudence and efficiency of the actual 2009 costs of utilities, rates and taxes in relation to establishing a benchmark of costs for 2009 (paragraph 821, above). This examination recognised that a large part of this cost item is access fees for the DBNGP land corridor, for which corroborating evidence has been provided.

876. Taking into account that the forecast costs are close in value to the benchmark cost of 2009, the Authority is satisfied that the forecast costs are consistent with the prudence and efficiency requirements of rule 91.

877. The Authority notes that DBP is currently engaging with the Department of Planning and Infrastructure seeking relief from some fees, which would reduce the costs for the 2011 to 2015 access arrangement period.[452] The Authority will be seeking further information on the outcomes of DBP's negotiation with the Department prior to a final decision on the proposed revised access arrangement.

Carbon Pollution Reduction Scheme Costs

878. DBP has included in the forecast of operating costs an amount in respect of costs that would be incurred by DBP under the emissions trading scheme that would have been introduced had the Commonwealth Government's previously proposed CPRS legislation been enacted. The DBP's forecast costs for 2011 to 2015 are shown in Table 65. There are no cost benchmarks for prior years.

Table 65 Forecast CPRS costs for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
CPRS Costs	0.000	0.000	8.600	9.300	9.528	10.111	10.669

452 Halcrow & Zincara, pp. 206, 207.

879. DBP's forecasts of CPRS costs are estimates of costs that would have been incurred by DBP as a liable entity (as a major energy user and emitter) with an obligation for surrendering "Australian energy units" under the CPRS.[453] DBP acknowledged an element of uncertainty in the forecast of CPRS costs and addressed this uncertainty through the reference tariff variation mechanism included in the proposed revised access arrangement (addressed at paragraph 965 and following of this draft decision).

880. The Authority considers that it was reasonable for DBP to include estimates of CPRS in the forecast of operating costs given that the proposed CPRS legislation was before Parliament at the time that DBP submitted its proposed revised access arrangement in April 2010. However, since this time the proposed CPRS legislation has been defeated and it is currently uncertain if and when a scheme to reduce carbon emissions will be introduced and, if it is, what the cost implications for major energy using businesses would be.

881. The Authority accepts that DBP may incur costs over the 2011 to 2015 access arrangement period as a result of the introduction of a scheme to address carbon emissions. The Authority further accepts that it is reasonable that provision be made in the access arrangement for these costs to be recoverable through reference tariffs.

882. There are three mechanisms that may be included in the access arrangement to enable the costs of a scheme to address carbon emissions to be recoverable through reference tariffs:

- inclusion of an estimate of costs in the forecast of operating expenditure;
- inclusion in the access arrangement of a trigger mechanism for review of the access arrangement in the event that a scheme to address carbon emissions is created that would result in significant costs being incurred by DBP; and
- inclusion in the access arrangement of provision under the reference tariff variation mechanism for a pass through of costs of a scheme to address carbon emissions, if and when such costs are incurred.

883. The Authority is of the view that the prospect and possible form of a scheme to address carbon emissions are too uncertain for an estimate of costs to be included in the forecast of operating expenditure. As such, the Authority will require amendment of the proposed revised access arrangement to remove costs of the CPRS from the forecast of operating expenditure.

884. The Authority will, however, allow the access arrangement to include provision for these costs to be addressed by a reference tariff variation mechanism, as addressed elsewhere in this draft decision (paragraph 965 and following).

Self-Insurance Costs

885. DBP has included in the forecast of operating costs an amount in respect of costs of self insurance. DBP's forecast costs for 2011 to 2015 are shown in Table 66. There are no cost benchmarks for prior years.

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[453] DBP, 14 April 2010, Submission # 12, pp 20, 21.

Table 66 Forecast self-insurance costs for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Self-insurance	-	-	0.228	0.228	0.228	0.228	0.227

886. DBP indicates that the self insurance costs comprise compensation for certain risks for which it has not sought to obtain insurance cover because of cost, or because it is unable to obtain cover.[454]

887. DBP's submission suggests that the risks that DBP considers are covered by self insurance are as follows.[455]

- Computer crime: direct loss arising from fraudulent third parties (excludes employee acts) accessing the insured's computer systems, communications systems (including Internet) and all funds transfer networks. Cover applies to funds, electronic securities at Central Depositories and PABX phone systems and consumer voice based transfer systems.
- General Property (also known as Special Risks): covers loss of or damage to specified property normally of a specialised nature which is not covered under a fire or industrial special risks policy.
- Accounts Receivable: compensates for amounts owing from customers (provided the insured cannot collect) as the direct result of loss or damage by an insured peril to records of accounts receivable contained at the insured's premises.
- Computer Breakdown/Business Interruption: covers the subsequent financial loss as a result of interruption to the business as a result of physical loss or damage including mechanical or electrical breakdown to computing equipment.
- Credit: to cover losses due to insolvency of companies or customers who are unable to honour their debts.
- Crisis Management / Contingency Expenses: covers the cost of crisis management and containment expenses from professional advisors selected by the insurer and following a loss under a CGL or in some cases Crime/D&O policies.
- Intellectual Property (IP): this type of policy provides coverage for:
  - Infringement liability – addresses the cost of defending IP infringement suits as well as awards or settlements; normally provided for patent risks (although trademark and copyright can usually be included).
  - Abatement/enforcement – address the legal costs involved in entering valid IP rights, i.e. pursuing infringers; available for patents, copyrights and trademarks; provided on blanket or patent/copyright/trademark specific basis.

454 DBP, 14 April 2010, Submission # 12, pp. 18 – 20.

455 DBP, 14 April 2010, Submission # 12, pp. 18 – 20.

- Protection for loss of revenues/profits from patent invalidity or trade secrets misappropriation.
- Residual Value: Compensates for a decline in the market value of leased assets such as automobiles, aircraft etc. The cover can be structured to include losses from the booked residual value and is to protect against catastrophes.
- Employment Practices Liability: The trend towards claims and litigation over allegations such as sexual harassment in the workplace, discrimination and unfair dismissal appears to be culminating in a liability problem that is increasing in frequency and severity. Policy covers:
  - actual or constructive termination of an employee relationship in breach of the law;
  - misrepresentation or defamation;
  - infliction of emotional distress;
  - harassment – sexual or otherwise;
  - failure or refusal to hire a potential employee;
  - invasion of the right of privacy; and
  - victimisation.
- Environment Impairment: costs of offsite clean up of contaminants and on and off site third party bodily injury and property damage, to asbestos and lead abatement liability.
- Errors and Omissions: alleged wrongful acts, errors or omissions in the conduct of the insured's business.
- Legal Expenses: covers expenses in:
  - pursuing or defending an action arising from disputes with customers or suppliers for the sale, purchase, hire or supply of goods; or services;
  - defending employment contract actions brought against clients by their employees; and
  - defending any criminal prosecution made against the company, its directors or employees.
- Statutory Liability Insurance: Covers the fines, and costs and expenses related to fines, imposed as a result of an innocent breach of the many Acts which control company operations.
- Extortion, Bomb Threat, Kidnap and Ransom: Covers reimbursement of kidnap or extortion payments as well as reasonable fees and expenses incurred for us of an independent negotiator or consultant, and interest costs on loans or ransom payments and travel and accommodation expenses.
- Extra Territorial Workers' Compensation: workers' compensation liability in respect of managerial, clerical, sales and white collar technical personnel (whose normal place of employment with the insured is within any of the states or territories of Australia where the Insured maintains Workers' Compensation insurance) whilst such personnel are temporarily working elsewhere than in their state or domicile and sustain personal injuries or occupational disease including death resulting there-from.

- Key Man Costs: loss of income upon death or disability of a senior executive, key persons or directors. Costs of acquiring a suitable replacement, or incurred in the event of an executive's death.

888. DBP has not provided supporting evidence for the forecast cost of self insurance. Rather, DBP cites a precedent of an amount of $0.2 million per year (escalating for inflation) having been allowed under the access arrangement for the gas transmission network of GasNet Australia Limited.[456]

889. The self insurance cost allowance for Gas Net comprises an amount of $189,500.00 in 2006 dollar values ($211,725.00 in dollar values of 31 December 2010) and provides for self insurance in respect of insurer credit risk, extortion and bomb threats, employment practices, an amount of "uplift liability", key person risk and fraud risk.[457] The cost allowance for GasNet was supported by an actuarial assessment of the relevant risks and fair-value assessments of self-insurance costs.[458]

890. The Authority observes that the assessment of risks and self insurance costs for GasNet involved a consideration of risks that are specific to GasNet (i.e. the risk referred to as "uplift risk") or were risks that may apply to GasNet and other similar businesses, but which were quantified taking into account specific characteristics of GasNet's business.

891. The Authority considers that an allowance in the forecast of operating expenditure for self insurance may be consistent with the prudence and efficiency criteria of rule 91 of the NGR if supported by relevant evidence in the form of an actuarial assessment of the risks and fair-value assessments of self-insurance costs. However, given that the risks and fair-value assessments will depend upon the particular characteristics of the businesses, the Authority does not accept that simple reference to costs allowed for in respect of another pipeline business is sufficient to demonstrate consistency with rule 91.

892. The Authority therefore considers that DBP has not demonstrated that the self-insurance costs are consistent with the prudence and efficiency criteria of rule 91 and the Authority will require amendment of the forecast of operating expenditure to remove allowance for these costs.

Miscellaneous Expenses

893. The benchmark cost of miscellaneous expenses for 2009 and DBP's forecast costs for 2010 and for 2011 to 2015 are shown in Table 67.

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456 DBP, 14 April 2010, Submission # 12, p 18.

457 ACCC, 14 November 2000, Draft Decision Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System, p. 118. "Uplift liability" refers to a liability for payment of charges to Vencorp if GasNet fails to meet certain obligations in relation to the provision of transmission services.

458 SAHA International Limited, 27 April 2007, GasNet Self Insurance Risk Assessment (Attachment E to GasNet Access Arrangement Submissions 27 May 2007).

Table 67 Benchmark of miscellaneous expenses for 2009 and forecast expenditure for 2010 and for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Miscellaneous expenses	1.052	0.405	0.330	0.330	0.330	0.330	0.330
Per cent change		-61.5	-18.5	-0.1	0.1	0.0	0.0

894. Miscellaneous expenses are indicated by DBP to include costs of employee incentives and rewards (11 per cent of forecast 2011 costs), recruitment costs (22 per cent), sponsorships (13 per cent), health and safety training (11 per cent) and safety equipment and supplies (22 per cent).

895. DBP has not provided substantiating information for the forecast of miscellaneous costs, in particular DBP has not provided explanation for the large decrease in costs from 2009 to subsequent years.

896. Notwithstanding the lack of supporting information, but taking into account the forecast decline in costs from the levels of 2009, the Authority is of the view that the forecast of miscellaneous expenses is consistent with the prudence and efficiency requirement of rule 91.

Compressor Overhaul Costs

897. DBP has included in the forecast of operating costs a non-recurrent amount of costs for compressor overhauls. DBP's forecast costs for 2011 to 2015 are shown in Table 68. There are no cost benchmarks for prior years.

Table 68 Forecast compressor overhaul costs for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Compressor overhaul	0.000	0.000	8.788	8.788	8.789	8.788	8.788

898. DBP indicates that the forecast costs for compressor overhauls allow for three compressor overhauls per year[459] at a cost of $2.93 million per compressor (dollar values of 31 December 2010).

899. The Authority's expert engineering advisor is of the view that the scheduling of three compressor overhauls per year is consistent with the operating regime and maintenance requirements for the compressor units of the DBNGP.[460] However, the Authority's advisor indicates that DBP has not provided information (despite requests) to justify the unit rate for compressor overhauls, which is greater than the actual cost of the last compressor overhaul in 2009 of $2.12 million ($2.18 million in dollar values of 31 December 2010).

459 Halcrow & Zincara, p. 213.

460 Halcrow & Zincara, p. 213.

900. Taking into account the observed actual cost in 2009 for a compressor overhaul and the absence of justification for the higher costs forecast by DBP, the Authority considers that the forecast cost of compressor overhauls is not consistent with the prudence and efficiency requirement of rule 91.

901. The Authority will require amendment of the forecast of operating expenditure to include an allowance of $6.529 million per year for compressor overhauls, corresponding to a unit cost per compressor of $2.18 million (in dollar values of 31 December 2010)

Regulatory expenses

902. DBP has included in the forecast of operating costs a non-recurrent amount of costs for regulatory expenses. DBP's forecast costs for 2011 to 2015 are shown in Table 69. There are no cost benchmarks for prior years.

Table 69 Forecast regulatory expenses for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Regulatory expenses	-	-	-	0.049	0.049	0.048	0.606

903. DBP indicates that the forecast costs for regulatory expenses comprise costs for externally sourced technical, economic and legal work required in revision of the access arrangement, with the bulk of costs concentrated in 2014 and 2015.[461] DBP further indicates that these costs compare with an expected cost of $800,000 in 2010 for the current revisions of the access arrangement.

904. While DBP has indicated the nature of activities to which the regulatory expenses relate, it has not indicated how it has derived the forecast of costs. Nor has DBP provided information on actual costs for years prior to 2010. As such, the information provided by DBP does not provide any basis for the Authority to assess the consistency of the forecast expenses with the prudence and efficiency criteria of rule 91.

905. The Authority observes that the forecast cost of regulatory expenses in respect of review of the access arrangement in 2014 and 2015 ($1.21 million over 2014 and 2015) is greater than that value of $0.913 million that was allowed for allowed for under the current access arrangement for the current review of the access arrangement (all values as dollar values of 31 December 2010),[462] and also that there is a small additional allowance of costs ($49,000) in each other year of the access arrangement period.

906. The Authority accept that the small annual allowance of costs is justified and consistent with the prudence and efficiency requirements as there are regulatory tasks that would need to be undertaken routinely through the access arrangement period.

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461 DBP, 14 April 2010, Submission #12, p. 21.

462 Economic Regulation Authority, 2 November 2005, Final Decision on proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, p. 59.

907. However, in the absence of substantiating information, the Authority is not satisfied that the increase in forecast costs for review of the access arrangement is consistent with the prudence and efficiency criteria of rule 91.

908. The Authority will require amendment of the forecast of operating expenditure to reduce the allowance for regulatory expenses to $49,000 in each of 2011 to 2013, and $0.505 million in each of 2014 and 2015, with the value for the latter years consistent with a forecast cost for review of the access arrangement of $0.913 million spread over the two years, together with the annual value of $49,000.

Fuel Gas

909. DBP has included in the forecast of operating costs a non-recurrent cost of fuel gas. DBP's forecast costs for 2011 to 2015 are shown in Table 70. There are no cost benchmarks for prior years.

Table 70 Forecast fuel gas costs for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2009 B/mark	2010 F/cast	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Fuel gas	-	-	20.427	21.585	21.495	23.679	24.118

910. The forecasts of fuel gas costs are based on:

- a forecast of steady-state fuel gas consumption derived using DBP's in-house forecasting model, which is the same model used for predicting fuel gas consumption for the 2005 to 2010 access arrangement period but with updated parameters to reflect the configuration of the pipeline after the stage 5A and 5B expansions;
- an allowance of 10 per cent of steady state fuel gas consumption to allow for extra fuel gas consumption under transient conditions, which is an increase from 5 per cent applied in the forecast of fuel gas use for the 2005 to 2010 access arrangement period; and
- prices for fuel gas as specified under contracts between DBP and Alinta (DBP's gas supplier).

911. DBP's forecast of fuel gas is premised on DBP providing all fuel gas for the DBNGP. However, DBP has entered into arrangements with at least one user for that user to provide fuel gas for its share of gas transportation in the pipeline. As such, the forecasts costs of fuel gas are in excess of actual costs that will be incurred by DBP. The Authority considers that this is not a matter of concern in determination of total revenue as, for the purposes of reference tariff calculation, total revenue is allocated across the total forecast of full-haul gas transmission. As such, users of the DBNGP other than the user that supplies its own fuel gas face only fuel gas costs in proportion to their use of transmission services.

912. With the exception of an amount of fuel gas use determined by DBP for compressor station CS10, the Authority is satisfied that DBP's prediction of fuel gas use under steady state conditions provides a reasonably accurate prediction of fuel gas use, evident from a close correlation between predicted and actual fuel gas requirements except in periods where pipeline operations were disrupted by expansion activities.[463] For CS10, DBP has forecast an increase in fuel gas use from 1.5 TJ/day in 2011 to 2013, to 3.0 TJ/day in 2014 and 2015. This does not appear to be justified by an increase in gas throughput to delivery points downstream of CS10, with full haul throughput forecast to increase only from 719.7 TJ/day in 2013 to 732.5 TJ/day in 2015. The Authority is not satisfied that DBP has justified this increase in fuel gas use and associated fuel gas cost ($1.782 million per year in dollar values of 2010).

913. On the basis of expert technical advice, the Authority is not satisfied that the increased allowance for fuel gas use under transient conditions from 5 per cent to 10 per cent of steady state gas use has been adequately justified. This accounts for a value of fuel gas of approximately $0.87 million per year (dollar values of 31 December 2010).[464]

914. The Authority is satisfied that the forecast cost of fuel gas is appropriately based on the contracted price with DBP's gas supplier.

915. Taking into account the above matters, the Authority considers that the forecast cost of fuel gas is not consistent with the prudence and efficiency criteria of rule 91 as the increased allowance for use of fuel gas under transient conditions has not been justified.

916. The Authority will require amendment of the forecast operating expenditure to reflect a reduction in the allowance for fuel gas use under transient conditions from 10 per cent to 5 per cent of steady state gas use and a reduction in fuel use at CS10 from 3.0 TJ/day in 2014 and 2015 to 1.5 TJ/day in each of those years. The revised forecast of fuel gas costs is indicated in (Table 71).

Table 71 Revised forecast fuel gas costs for the 2011 to 2015 access arrangement period (real $million at 31 December 2010)

Year ending 31 December	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Proposed fuel gas cost	20.427	21.585	21.495	23.679	24.118
Revised fuel gas cost	19.609	20.713	20.627	21.009	21.434
Reduction	0.818	0.872	0.868	2.670	2.684

Conclusion on Prudence and Efficiency of Forecast Operating Expenditure in the 2011 to 2015 Access Arrangement Period

917. A revised forecast of operating expenditure by cost line item is shown in Table 72.

463 Halcrow & Zincara, pp. 220, 221.

464 Halcrow & Zincara, pp. 221, 222.

Table 72 Authority's revised forecast of operating expenditure for the 2011 to 2015 access arrangement period, by cost item (real $ million at 31 December 2010)

Year ending 31 December	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Recurrent costs					
Wages and salaries - salaries	25.017	25.505	26.003	26.510	27.028
Wages and salaries - contractors	1.392	1.419	1.446	1.474	1.503
Non-field expense - consulting	4.916	4.916	4.916	4.916	4.916
Non-field expense - entertainment expenses	0.129	0.129	0.129	0.129	0.129
Non-field expense - IT expenses	2.696	2.696	2.696	2.696	2.696
Non-field expenses - insurance costs	4.726	4.726	4.726	4.726	4.726
Field expense - motor vehicle expenses	0.937	0.937	0.938	0.938	0.938
Non-field expense - office and administration expenses	0.918	0.918	0.918	0.919	0.918
Field expense - repairs and maintenance expenses	5.062	5.062	5.062	5.062	5.062
Field expense - training & development expenses	1.193	1.194	1.193	1.193	1.193
Field expense - travel & accommodation expenses	2.133	2.133	2.133	2.133	2.133
Government charges – utilities, rates & taxes	10.974	10.974	10.974	10.974	10.974
Government charges - CPRS costs	0.000	0.000	0.000	0.000	0.000
Non-field expense - self insurance	0.000	0.000	0.000	0.000	0.000
Non-field expense - miscellaneous	0.330	0.330	0.330	0.330	0.330
Total recurrent costs	**60.424**	**60.940**	**61.466**	**62.000**	**62.547**
Non-recurrent costs					
Reactive maintenance	1.172	1.172	1.172	1.172	1.172
OSA Charges	0.000	0.000	0.000	0.000	0.000
Field Expense - compressor overhauls	6.529	6.529	6.529	6.529	6.529
Non-field expense - regulatory expenses	0.049	0.049	0.049	0.505	0.505
Fuel gas	19.609	20.713	20.627	21.009	21.434
Total non-recurrent costs	**27.358**	**28.462**	**28.377**	**29.216**	**29.640**
Total	**87.782**	**89.402**	**89.842**	**91.216**	**92.188**

918. For the reasons set out above and in the confidential Appendix 4, the Authority is not satisfied that DBP's forecast of operating expenditure is consistent with the prudence and efficiency criteria of rule 91.

919. The Authority requires amendment of the proposed revised access arrangement to include a forecast of operating expenditure in accordance with the summary of adjusted cost line items in Table 73. The Authority's revised forecast of operating expenditure is a reduction from DBP's proposed forecast by $91.7 million (in dollar values of 31 December 2010), equivalent to 16.9 per cent of the proposed forecast operating expenditure for the 2011 to 2015 access arrangement period.

Table 73 DBP's forecast operating expenditure for the 2011 to 2015 access arrangement period, by cost category (real $ million at 31 December 2010)[465]

Year ending 31 December	2011 F/cast	2012 F/cast	2013 F/cast	2014 F/cast	2015 F/cast
Wages & Salaries	26.408	26.924	27.449	27.985	28.531
Non-Field Expense	13.765	13.765	13.765	14.222	14.221
Field Expense	17.026	17.027	17.027	17.027	17.027
Government Charges	10.974	10.974	10.974	10.974	10.974
Fuel gas	19.609	20.713	20.627	21.009	21.434
Total	87.782	89.402	89.842	91.216	92.188

Required Amendment 10

The forecast of operating expenditure for the 2011 to 2015 access arrangement period must be amended to vales as indicated in Table 73 of this draft decision.

Total Revenue

Regulatory Requirements

920. Rule 76 of the NGR provides that total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach, where the building blocks are:

- a return on the projected capital base for the year; and
- depreciation on the projected capital base for the year; and
- if applicable – the estimated cost of corporate income tax for the year; and

465 DBP, 1 April 2010, revised access arrangement information sections 4, 9.

- increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency; and
- a forecast of operating expenditure for the year.

DBP's Proposed Revisions

921. DBP's proposed calculation of total revenue for each year of the 2011 to 2015 access arrangement period is set out in section 17 of the revised access arrangement information. Total revenue has been calculated as the sum of:

- a return of on the projected capital base for the year;
- depreciation on the projected capital base for the year;
- if applicable, increments or decrements for the year resulting from the operation of the incentive mechanism that previously existed; and
- a forecast of operating expenditure for the year.

922. No amounts included in the calculation of total revenue for the estimated cost of corporate income tax, which is addressed in the rate of return.

923. DBP's proposed total revenue is shown in Table 74.

Table 74 DBP's proposed calculation of total revenue for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)[466]

Year ending 31 December	2011	2012	2013	2014	2015
Return on capital base	366.124	363.773	355.445	346.790	338.011
Depreciation	93.818	95.840	96.231	96.618	97.020
Incentive mechanism	10.486	10.231	-	-	-
Operating expenditure	104.341	106.717	107.382	111.242	112.787
Total	**574.769**	**576.560**	**559.058**	**554.650**	**547.818**
Present value (real pre-tax WACC of 10.76 per cent)	**2,097.478**				

924. In support of its calculation of target revenue (and in addition reference tariffs), DBP has provided to the Authority further information in a confidential supporting submission.[467]

Submissions

925. None of the submissions made to the Authority address the calculation of total revenue.

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466 DBP, 1 April 2010, Revised access arrangement information, section 17.3 (Table 22).

467 DBP, 14 April 2010, Confidential supporting submission #4: Basis for total revenue and reference tariff. A public version of this submission is available to interested parties.

Considerations of the Authority

926. The Authority has calculated the total revenue for the 2011 to 2015 access arrangement period, taking into account the corrections to DBP's calculations and the amendments to components of the calculation as set out in the preceding sections of this draft decision. Given DBP's proposed treatment of capital contributions (where the contributions are added to the capital base, but quarantined from determination of total revenue) the calculation of total revenue is calculated on the basis of a return on capital base and depreciation for the "DBP assets" component of the capital base as shown in Table 24 of this draft decision.

927. The corrected and amended calculation of total revenue is set out in Table 75.

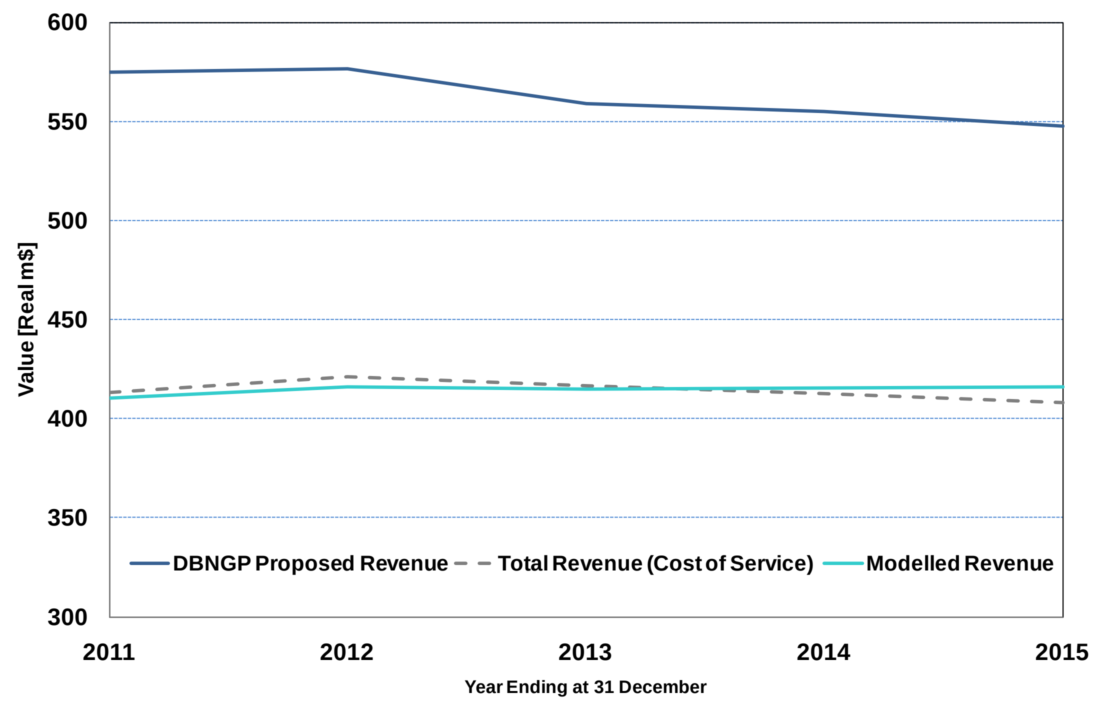
Table 75 Authority's corrected and amended calculation of total revenue for the 2011 to 2015 access arrangement period (real $ million at 31 December 2010)

Year ending 31 December	2011	2012	2013	2014	2015
Return on capital base	241.760	240.046	234.509	228.760	222.844
Depreciation	89.774	91.775	92.186	92.487	92.785
Incentive mechanism	-	-	-	-	-
Correction for over-depreciation	-6.445	-	-	-	-
Operating expenditure	87.782	89.403	89.842	91.216	92.188
Total	**412.871**	**421.224**	**416.538**	**412.463**	**407.817**
Present value (real pre-tax WACC of 7.16 per cent)	**1,691.847**				

928. The values of the total revenue as proposed by DBP and determined in this draft decision are shown in Figure 9.[468]

[468] Information from the Authority's financial model used to calculate Total Revenue and Reference Tariffs is provided in Appendix 5 of this draft decision.

Figure 9: Comparison of proposed and draft decision values of total revenue (in real terms).



Allocation of Total Revenue between Reference Services and Other Services

Regulatory Requirements

929. Rule 93 of the NGR requires that total revenue is allocated between reference services and other services on the basis of an allocation of costs. As an alternative to cost allocation, rule 93 provides for services other than reference services to be classed as rebateable services, with part of the revenue from sale of these services to be rebated or refunded to users of reference services. The particular requirements of rule 93 are as follows.

93 Allocation of total revenue and costs

(1) Total revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services.

(2) Costs are to be allocated between reference and other services as follows:

(a) costs directly attributable to reference services are to be allocated to those services; and

(b) costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and

(c) other costs are to be allocated between reference and other services on a basis (that must be consistent with the revenue and pricing principles) determined or approved by the [Authority].

(3) The [Authority] may, however, permit the allocation of the costs of rebateable services, in whole or in part, to reference services if:

(a) the [Authority] is satisfied that the service provider will apply an appropriate portion of the revenue generated from the sale of rebateable services to provide price rebates (or refunds) to the users of reference services; and

(b) any other conditions determined by the [Authority] are satisfied.

(4) A pipeline service is a rebateable service if:

(a) the service is not a reference service; and

(b) substantial uncertainty exists concerning the extent of the demand for the service or of the revenue to be generated from the service; and

(c) the market for the service is substantially different from the market for any reference service.

DBP's Proposed Revisions

930. DBP has not proposed any allocation of total revenue to services other than reference services (non-reference services) and has not proposed that any service be a rebateable service.

Submissions

931. One party has submitted that it does not appear that DBP has taken into account other services in calculating forecast demand, such as those arising from LPG content, Tx service, Tp service and other non-reference services. This party contends that the revenue streams generated from these services should be taken into account to reduce the amount of revenue sought to be recovered by way of the reference tariff. An alternative is to provide a rebate to shippers, but this is seen as a complicated option to implement.[469]

932. The Authority has addressed this matter below by consideration of an allocation of costs between reference services and other services that DBP may provide.

Considerations of the Authority

933. Under rule 93 of the NGR and allocation of total revenue between reference services and non-reference services is required.

934. DBP has not proposed any allocation of total revenue to services other than services in the nature of the proposed reference service. DBP further submits that none of the forecast costs included in the total revenue under the proposed revised access arrangement relate to the provision of non reference services and, therefore, there is no reason to allocate a part of the costs included in the total revenue to the provision of services other than reference services.[470]

[469] Wesfarmers Chemicals, Energy & Fertilisers, 9 July 2010.

[470] DBP, 7 January 2011, Submission #35 paragraphs 6.3 and 6.4.

935. The relevant matters for the Authority's consideration in whether there should be an allocation of a part of forecast costs (and of total revenue) to the provision of services other than reference services are:

- the quantum and nature of the non-reference services that may reasonably be expected to be provided during the 2011 to 2015 access arrangement period; and
- whether part of the costs included in the total revenue can be attributed to provision of non-reference services and, hence, should be allocated to these services rather than allocated to reference services.

936. The Authority has also considered whether any non-reference services should be explicitly declared to be rebateable services and, if so, the terms of rebate mechanisms.

937. In a submission to the Authority subsequent to lodging the proposed revised access arrangement, DBP indicates that non-reference services may comprise:

- park & loan, storage and delivery services;
- spot services;
- interruptible services;
- co-mingling services;
- commissioning services;
- inlet swap services;
- out of specification gas services.[471]

938. DBP does not forecast any utilisation of these pipeline services in the 2011 to 2015 access arrangement period.[472] Past sales of non-reference services supports DBP's contention of there being limited sales of non-reference services for the 2011 to 2015 access arrangement period. DBP indicates that there was limited provision of non-reference services during the 2005 to 2010 access arrangement period, with revenue from non-reference services amounting to $21.9 million, with almost $11 million of that revenue being earned in 2009 and the first half of 2010, largely as a consequence of the Varanus Island explosion. This amount of revenue and sale of non-reference services in the 2005 to 2010 access arrangement period is small relative to the total revenue that was determined for reference services in that period of over $1.5 billion in nominal terms.

939. However, the Authority considers that there could be some sales of these non-reference services during the 2011 to 2015 access arrangement period. As DBP expects that the firm full-haul capacity of the DBNGP will be fully contracted for the 2011 to 2015 access arrangement period, it is possible that users of the DBNGP will seek to meet requirements for additional service requirements through non-reference services. Moreover, the Authority is aware that there are some significant gas users that do not hold gas supply and gas transmission contracts, but rather look to secure gas supplies through short-term arrangements, which may include non-reference services provided by DBP.

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471 DBP, 7 January 2011, Submission #35.

472 DBP, 7 January 2011, Submission #35 paragraph 5.2.

940. Given a lack of information to make a reliable forecast of demand for non-reference services in the 2011 to 2015 access arrangement period, the Authority has not allocated any costs to non-reference services.

941. Notwithstanding the absence of a lack of information to make a reliable forecast of demand for non-reference services, the Authority considers that there is some significant likelihood of demand for non-reference services emerging over the access arrangement period. For this reason, the Authority takes the view that the access arrangement should make an explicit declaration that non-reference services for gas transportation are rebateable services.

942. The rebate mechanism should make provision for a share of revenue over and above the incremental cost of service provision to be rebated to users of services that are in the nature of reference services.

943. Under this draft decision, the Authority is requiring that the commodity charge of reference tariffs be at a level approximately equal to the incremental cost of a unit of gas throughput (refer to paragraph 956, below). The Authority considers that the commodity charge is a reasonable approximation of the incremental cost of service provision for non-reference services.

944. The Authority further considers that the rebate mechanism should provide for 80 per cent of revenue in excess of the incremental cost of service provision to be rebated to users of services that are in the nature of reference services.

945. With these parameters of a rebate mechanism, the Authority requires the following amendment to the proposed revised access arrangement.

Required Amendment 11

The proposed revised access arrangement should be amended to include a statement that services for gas transportation that are other than services in the nature of reference services are rebateable services within the meaning of rule 93(4).

The access arrangement should also include a rebate mechanism that provides for a share of revenue from rebateable services to be rebated to users of services that are in the nature of reference services. The rebate mechanism should provide for the share of revenue to be rebated as:

Value of revenue to be rebated $=0.8 \times (R - (C \times Q)$

where

R is the revenue from the rebateable service ($);

C is the commodity tariff of the full haul, part haul or back haul reference service, as relevant ($/GJ); and

Q is the throughput quantity of the rebateable service.

Reference Tariffs

Regulatory Requirements

946. Rule 95 of the NGR sets out requirements for the determination of reference tariffs for transmission pipelines.

95 Tariffs – transmission pipelines

(1) A tariff for a reference service provided by means of a transmission pipeline must be designed:

(a) to generate from the provision of each reference service the portion of total revenue referable to that reference service; and

(b) as far as is practicable consistently with paragraph (a), to generate from the user, or the class of users, to which the reference service is provided, the portion of total revenue referable to providing the reference service to the particular user or class of users.

(2) The portion of total revenue referable to a particular reference service is determined as follows:

(a) costs directly attributable to each reference service are to be allocated to that service; and

(b) other costs attributable to reference services are to be allocated between them on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the [Authority].

(3) The portion of total revenue referable to providing a reference service to a particular user or class of users is determined as follows:

(a) costs directly attributable to supplying the user or class of users are to be allocated to the relevant user or class; and

(b) other costs are to be allocated between the user or class of users and other users or classes of users on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the [Authority].

(4) The [Authority's] discretion under this rule is limited.

DBP's Proposed Revisions

947. DBP has proposed a reference tariff for the single proposed reference service, the R1 Service.

948. Information provided in the revised access arrangement information indicates that the Reference Tariff for the R1 Service has been determined to recover 100 per cent of DBP's proposed value of total revenue (in present value terms).[473] This implies an assumption that all gas transportation in the DBNGP occurs under the R1 reference service.

949. The proposed reference tariff for the R1 Service comprises two tariff charges:

- the capacity reservation tariff, set to recover all costs except the cost of fuel gas and comprising approximately 96 per cent of the total tariff; and
- the commodity tariff, set to recover the cost of fuel gas and comprising approximately 4 per cent of the total tariff.[474]

950. The proposed values of these component tariffs at 1 January 2010 are:

- capacity reservation tariff of $1.648018/GJ;
- commodity tariff of $0.079975/GJ.[475]

951. The total tariff for the R1 Service for gas transportation at 100 per cent load factor would be $1.727993/GJ.

952. The reference tariff values have been calculated on the basis of a forecast of reserved capacity and pipeline throughput as shown in Table 76.

473 Revised access arrangement information, pp 30, 35.

474 Revised access arrangement information, pp 28 – 30.

475 Proposed access arrangement revisions, clause 3.2. The tariff values stated in the proposed access arrangement have been escalated for inflation to the values that would apply in 2011.

Table 76 DBP forecasts of capacity and throughput applied in determination of the proposed reference tariff for the R1 Reference Service

	2011	2012	2013	2014	2015
DBNGP forecast full haul contracted capacity	851.310	860.310	860.310	860.310	860.310
DBP forecast full haul throughput	703.074	718.817	719.717	725.846	732.521

Submissions

953. Submissions made to the Authority have expressed the following concerns with the determination of reference tariffs.

- The forecast of demand may be unreasonably low resulting in reference tariffs being substantially higher than they should be, taking into account new gas supplies that will commence during the 2011 to 2015 access arrangement period.[476]
- A proposed reduction in the commodity tariff to 5 per cent of the total tariff is unreasonable.[477] This is particularly the case for users with peaky loads.[478]

Considerations of the Authority

954. As an element of this draft decision, the Authority is requiring amendment of the proposed revised access arrangement to remove the proposed R1 Service and include a full haul “T1 reference service”, part haul “P1 reference service” and back haul “B1 reference service” in accordance with the reference services available under the access arrangement for the 2005 to 2010 access arrangement period. Accordingly, the Authority has determined tariffs for the required reference services rather than undertaking an assessment of DBP’s proposed reference tariff for the R1 Service.

955. The Authority considers that the general structure and specification of reference tariffs under the access arrangement for the 2005 to 2010 access arrangement period is consistent with the requirements of rule 95 of the NGR, that is:

- the reference tariffs should comprise two charges, a capacity reservation charge (in units of $/GJ MDQ) and a commodity charge (in units of $/GJ);
- the reference tariff charges for the T1 reference service should be independent of distance;
- the reference tariff charges for the P1 and B1 reference services should be specified as a distance-based function of the reference tariff for the T1 reference service –

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476 Wesfamers Chemicals, Energy & Fertiliser, 9 July 2010.

477 Wesfamers Chemicals, Energy & Fertiliser, 9 July 2010.

478 Verve Energy, [undated]; Synergy, 9 July 2010; Alinta Pty Ltd 9 July 2010.

$$F \times \frac{D}{1399}$$

where

F is the value of the charge that would apply if the service were the T1 reference service; and

D is the distance in kilometres of pipeline between the relevant receipt point and the relevant delivery point.

956. Under the access arrangement for the 2005 to 2010 access arrangement period, the allocation of costs between the capacity reservation charge and the commodity charge is made on the basis of allocating fuel costs for recovery by the commodity charge and allocation of all other costs for recovery by the capacity reservation charge. The Authority has considered this allocation of costs against the particular requirements of rule 95 and is of the view that this allocation does not result in an allocation of costs between reference services and between users that is consistent with the requirements of rule 95(2) and (3). The Authority considers that a substantial part of operating expenditure, particularly costs categorised by DBP as field expenses and reactive maintenance, is closely correlated with throughput and should be recovered through the commodity charge.

957. The Authority has calculated the charges of the reference tariffs for the T1, P1 and B1 reference services based:

- the value of total revenue determined in this draft decision;
- an allocation of fuel costs, field expenses and reactive maintenance costs to commodity charges; and
- forecasts of demand for firm full haul, part haul and back haul services as supplied by DBP.

958. A summary of the forecasts of demand applied in determination of amended reference tariffs are shown in Table 77.

Table 77 Summary of demand forecasts applied by the Authority in determination of amended reference tariffs

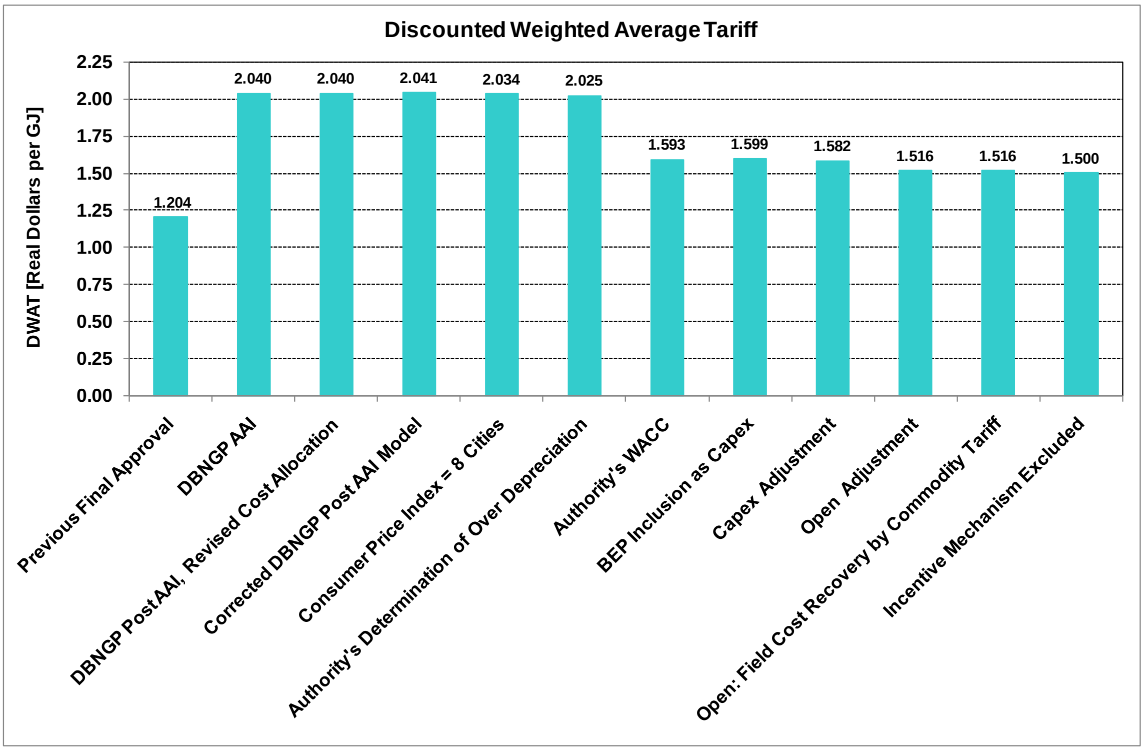
	2011	2012	2013	2014	2015
T1 reference service					
Capacity (TJ/day)	851.310	860.310	860.310	860.310	860.310
Throughput (TJ/day)	703.074	718.817	719.717	725.846	732.521
Average load factor	0.826	0.836	0.837	0.844	0.851
P1 reference service					
Capacity (TJ/day)	215.380	215.380	215.380	215.380	215.380
Throughput (TJ/day)	191.458	189.708	189.708	189.708	189.708
Average load factor	0.889	0.881	0.881	0.881	0.881
B1 reference service					
Capacity (TJ/day)	130.047	130.047	130.047	130.047	130.047
Throughput (TJ/day)	112.267	112.267	112.267	112.267	112.267
Average load factor	0.863	0.863	0.863	0.863	0.863

959. The Authority acknowledges the concern expressed in submissions over the potential that the forecast demand is too low. However, the Authority has not received any substantive information from users or prospective users on prospects for additional demand. For this reason, the Authority has not sought to revise the forecasts provided by DBP.

960. In calculating the amended reference tariffs, the Authority has necessarily had regard to more detailed forecasts of part haul and back haul contracted capacity and throughput and to distances of gas transportation for each delivery point. In information provided to the Authority by DBP, there are minor differences in stated distances of gas transmission to distances previously applied in tariff calculations, and also to distances specified in the DBNGP system description. The Authority has corrected these distances in its financial model.

961. The reference tariffs derived by the Authority are set out in Table 78 and are the reference tariffs that would apply for 2011. The 100 per cent load factor tariffs are 25.8 per cent lower than proposed by DBP. The elements of the Authority's draft decision that give rise to the reduction in the tariff can be illustrated as an effect on the discounted weighted average tariff for the DBNGP, as shown in Figure 10.

Figure 10: Effect of elements of the Authority's draft decision on the discounted weighted average tariff for the DBNGP.



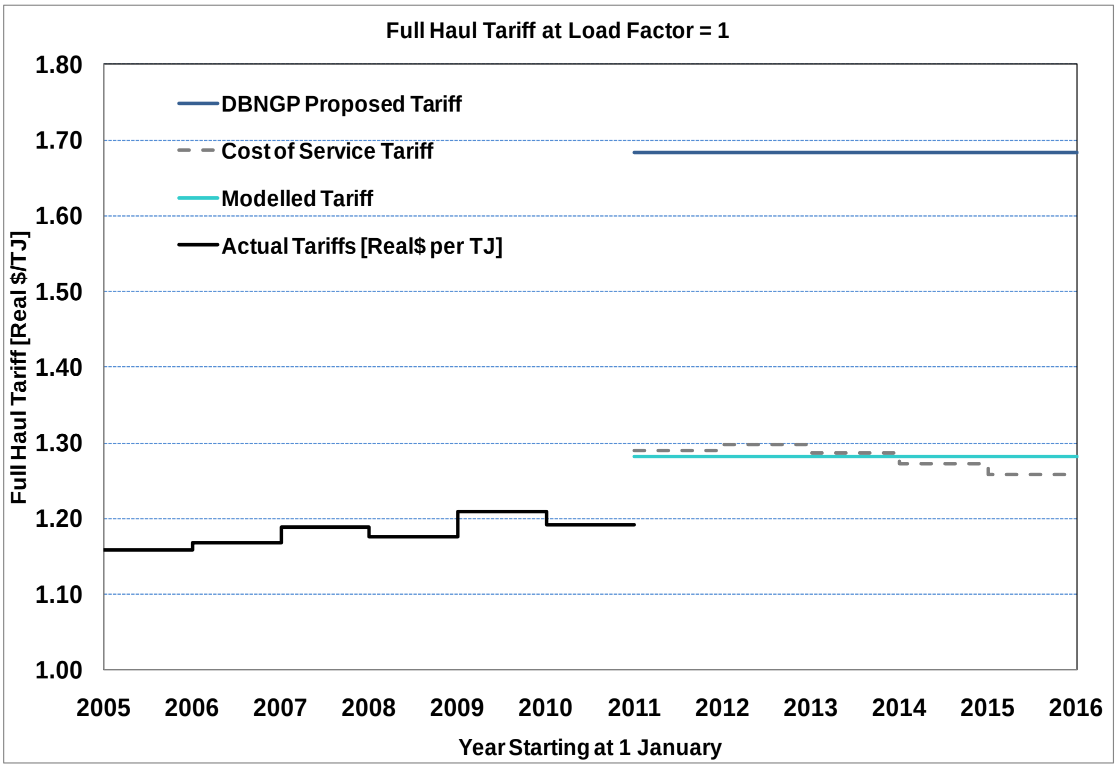
962. The reference tariffs that would apply for subsequent years of the 2011 to 2015 access arrangement period would be the values indicated in Table 78 with escalation for inflation.

Table 78 Amended reference tariff charges for the T1, P1 and B1 reference services (real dollar values at 31 December 2010)

Reference Service and reference tariff charge	Units	DBP Proposed	Amended
T1 reference service			
Capacity reservation charge	$/GJ MDQ	1.648018	1.145584
Commodity charge	$/GJ	0.079975	0.136310
Total charge at 100% load factor	$/GJ	1.727993	1.281894
P1 and B1 reference services			**Value**
Capacity reservation charge	$/GJ MDQ*km	0.0011780	0.0008189
Commodity charge	$/GJ*km	0.0000572	0.0000974
Total charge at 100% load factor	$/GJ*km	0.0012352	0.0009163

963. The values of the reference tariff for the T1 Service as proposed by DBP and determined in this draft decision are shown in Figure 11.

Figure 11 Comparison of proposed and draft decision values of the reference tariff for the T1 Service (in real terms)



964. The Authority requires the following amendment to the proposed revised access arrangement to include the reference tariffs for the T1, P1 and B1 reference services.

Required Amendment 12

The proposed revised access arrangement should be amended to specify the reference tariff charges for the T1 reference service for the calendar year 2011 as:

Capacity Reservation Charge: $1.145584/GJ MDQ

Commodity Charge: $0.136310/GJ

The proposed revised access arrangement should be amended to provide for determination of the corresponding reference tariff charges for the P1 and B1 reference services for the calendar year 2011 as:

Reference tariff charge = F × D/1399

where

F is the value of the charge that would apply if the service were the T1 reference service; and

D is the distance in kilometres of pipeline between the relevant receipt point and the relevant delivery point.

Tariff Variation Mechanism

Regulatory Requirements

965. Rules 92 and 97 of the NGR set out requirements for an access arrangement to include a mechanism for variation of reference tariffs during an access arrangement period.

92 Revenue equalisation

(1) A full access arrangement must include a mechanism (a reference tariff variation mechanism) for variation of a reference tariff over the course of an access arrangement period.

(2) The reference tariff variation mechanism must be designed to equalise (in terms of present values):

(a) forecast revenue from reference services over the access arrangement period; and

(b) the portion of total revenue allocated to reference services for the access arrangement period.

(3) However, if there is an interval (the interval of delay) between a revision commencement date stated in a full access arrangement and the date on which revisions to the access arrangement actually commence:

(a) reference tariffs, as in force at the end of the previous access arrangement period, continue without variation for the interval of delay; and

(b) the operation of this subrule may be taken into account in fixing reference tariffs for the new access arrangement period.

…

97 Mechanics of reference tariff variation

(1) A reference tariff variation mechanism may provide for variation of a reference tariff:

(a) in accordance with a schedule of fixed tariffs; or

(b) in accordance with a formula set out in the access arrangement; or

(c) as a result of a cost pass through for a defined event (such as a cost pass through for a particular tax); or

(d) by the combined operation of 2 or more or the above.

(2) A formula for variation of a reference tariff may (for example) provide for:

(a) variable caps on the revenue to be derived from a particular combination of reference services; or

(b) tariff basket price control; or

(c) revenue yield control; or

(d) a combination of all or any of the above.

(3) In deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the [Authority] must have regard to:

(a) the need for efficient tariff structures; and

(b) the possible effects of the reference tariff variation mechanism on administrative costs of the [Authority], the service provider, and users or potential users; and

(c) the regulatory arrangements (if any) applicable to the relevant reference services before the commencement of the proposed reference tariff variation mechanism; and

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

(e) any other relevant factor.

(4) A reference tariff variation mechanism must give the [Authority] adequate oversight or powers of approval over variation of the reference tariff.

(5) Except as provided by a reference tariff variation mechanism, a reference tariff is not to vary during the course of an access arrangement period.

DBP's Proposed Revisions

966. DBP has proposed a reference tariff variation mechanism that provides for the following variations of the reference tariff:

- annual inflation escalation, with the tariff charges escalated in accordance with changes in the "All Groups – Perth" consumer price index;
- pass through of changes in taxation costs and "carbon costs", which include "any costs 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 in so far as the obligation or liability is connected to the DBNGP"; and
- pass through of "new costs", comprising costs that are beyond the control of the DBNGP Operator or its related bodies corporate and that could not be predicted at the time the revisions to the access arrangement were approved and were not included in the total revenue for one or more years of the current access arrangement.[479]

967. The reference tariff variation mechanism provides for the Authority to be notified of variations to the reference tariff and to be provided with supporting information and calculations for the variation. For a reference tariff variation by inflation escalation, the Authority is to be notified no later than 10 days after a reference tariff variation has been bought into effect. For a reference tariff variation in respect of taxation costs, carbon costs or new costs, the Authority is to be notified no later than 15 days before a variation to the reference tariff commences to have effect.

[479] Proposed access arrangement revisions, clause 11.

Submissions

968. Submissions made to the Authority have expressed the following concerns with the proposed reference tariff variation mechanism.

- Inflation escalation of reference tariffs should occur on the basis of the All Groups, Eight Capital Cities CPI.[480]
- The proposed reference tariff variation mechanism provides for full inflation escalation of reference tariffs, whereas productivity improvements by DBP should mean that cost and therefore tariff increases beyond the first year of the term can be limited to something less than CPI.[481,482,483]
- The proposed tariff variation mechanism includes a tax change variation that relates primarily to the introduction of a CPRS or similar measure. Proposals in the revised access arrangement to deal with a CPRS are unnecessary and no longer appropriate.[484]
- The tax changes variation mechanism component of the tariff variation mechanism be amended so as to provide a mechanism through which DBP is allowed to pass through the costs that might be incurred under a CPRS (or similar scheme); and the definition of Tax Change be amended accordingly.[485,486]
- The scope of the carbon cost variation should be tightly defined and should be subject to reasonable limits on costs that may be recovered, and costs should be subject to audit and dispute resolution.[487]
- The new cost pass through variation mechanism is unreasonably broad, and in any event does not meet the requirements set out in NGR 97(1) for a tariff variation mechanism.[488,489]

Considerations of the Authority

969. The Authority has considered the elements of the proposed reference tariff variation mechanism against the provisions of rules 92 and 97.

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480 Alinta Pty Limited, 9 July 2010.
481 Wesfamers Chemicals, Energy & Fertiliser, 9 July 2010.
482 Wesfamers Chemicals, Energy & Fertiliser, 9 July 2010.
483 Rio Tinto, 20 July 2010.
484 Verve Energy, 9 July 2010.
485 Alinta Pty Limited, 9 July 2010.
486 Rio Tinto, 20 July 2010.
487 Rio Tinto, 20 July 2010.
488 Alinta Pty Limited, 9 July 2010.
489 BHP Billiton, 9 July 2010.

970. The Authority considers that annual inflation escalation of reference tariffs is consistent with the requirement of rule 92(2) that the reference tariff variation mechanism must be designed to equalise (in present value terms) the forecast revenue from reference services over the access arrangement period and the portion of total revenue allocated to reference services for the access arrangement period. Annual escalation for inflation is consistent with the financial calculations used by DBP and by the Authority in determining the initial values of reference tariffs for 2011 such that a constant value of tariffs in real terms over the access arrangement period is forecast to return the value of total revenue allocated to reference services.

971. For reasons set out earlier in the draft decision (paragraphs 105 and 106), the Authority considers that the CPI values applied in the determination of reference tariffs should consistently be the “All Groups – 8 Capital Cities” consumer price index. Accordingly, the Authority requires the reference tariff variation mechanism to be amended to base inflation escalation of reference tariffs on movements in the All Groups – 8 Capital Cities CPI.

Required Amendment 13

The proposed revised access arrangement should be amended to change the definition of CPI in the reference tariff variation mechanism to “CPI means the Consumer Price Index, All Groups, Eight Capital Cities.

972. The Authority considers that variation in reference tariffs for the pass through of costs of taxation changes and of carbon costs is consistent with the provision of rule 97(1)(c) for a reference tariff variation mechanism to “provide for variation of a reference tariff as a result of a cost pass through for a defined event (such as a cost pass through for a particular tax)”.

973. The Authority considers, however, that the scope in the reference tariff variation mechanism for the pass through of these costs is not sufficiently constrained and the pass through of the costs should be subject to the same regulatory assessment and approval as for forecasts of costs in the normal process of approval of proposed revisions to the access arrangement. In particular, the pass through of these costs should be subject to the Authority being satisfied that the costs are consistent with the criteria governing operating expenditure set out in rule 91. The Authority also considers that the pass through of these costs should be subject to the Authority’s approval, as contemplated by rule 97(4).

Required Amendment 14

The proposed revised access arrangement should be amended so that the variation of reference tariffs by way of a Tax Changes Variation:

- is limited to costs of tax changes that satisfy the criteria governing operating expenditure set out in rule 91 of the NGR; and
- is subject to the Authority’s approval of the variation.

974. The Authority considers that provision under the proposed reference tariff variation mechanism for the pass through of "new costs" is not permitted under rule 97 which (at rule 97(1)(3)) provides for a cost pass through only in respect of a defined event. The proposed provision for pass through of new costs is a broad provision not limited to defined events.

Required Amendment 15

The proposed revised access arrangement should be amended to remove provision under the reference tariff variation mechanism for the variation of reference tariffs by way of a "new costs pass through variation".

Fixed Principles

Regulatory Requirements

975. Rule 99 of the NGR provides for an access arrangement to include fixed principles:

99 Fixed principles

(1) A full access arrangement may include a principle declared in the access arrangement to be fixed for a stated period.

(2) A principle may be fixed for a period extending over 2 or more access arrangement periods.

(3) A fixed principle approved before the commencement of these rules, or approved by the [Authority] under these rules, is binding on the [Authority] and the service provider for the period for which the principle is fixed.

(4) However:

(a) the [Authority] may vary or revoke a fixed principle at any time with the service provider's consent; and

(b) if a rule is inconsistent with a fixed principle, the rule operates to the exclusion of the fixed principle.

DBP's Proposed Revisions

976. Clause 13 of the proposed revised access arrangement sets out the fixed principles to apply under the access arrangement:

13. FIXED PRINCIPLES [R.99]

(a) The following are Fixed Principles in accordance with rule 99 of the NGR:

(i) the method of determination of the Capital Base at the commencement of each year of each access arrangement period as set out in section 7 of the Current Access Arrangement Information;

(ii) the revenue earned by Operator during the period commencing on 1 July 2005 and ending on 31 December 2015 from the sale of any Services which is in excess of the amount (in net present value terms) equal to the sum of:

(A) the revenue that would have been earned had any of those services which were Full Haul Services been sold at the Reference Tariff; and

(B) the revenue actually earned from the sale of those services which were services other than Full Haul Services,

must not:

(C) be taken into account directly or indirectly for the purposes of setting a Reference Tariff or determining or applying any aspect of the price and revenue elements of the Access Arrangement which applies on or after 1 January 2011; or

(D) otherwise be taken into account directly or indirectly by the relevant Regulator in performing any of its functions under the NGA, NGL or NGR.

(b) For the purposes of the Fixed Principles referred to in clause 13(a) of this Access Arrangement, the fixed period is until 31 December 2031.

977. These fixed principles are materially the same as the “reference tariff principles not subject to review” as set out in clause 7.13 of the access arrangement for the 2005 to 2010 access arrangement period, reproduced as follows.

7.13 Reference Tariff Principles Not Subject to Review

(a) The following are Fixed Principles in accordance with section 8.47 of the Code:

(i) the method of determination of the Capital Base at the commencement of each year of the Access Arrangement Period as set out in clause 7.3 of the Access Arrangement;

(ii) the revenue earned by Operator during the period commencing on 1 July 2005 and ending on 31 December 2015 from the sale of any Services which is in excess of the amount (in net present value terms) equal to the sum of:

(A) the revenue that would have been earned had any of those Services which were Full Haul Services been sold at the Reference Tariff; and

(B) the revenue actually earned from the sale of those Services which were Services other than Full Haul Services,

must not:

(C) be taken into account directly or indirectly for the purposes of setting a Reference Tariff or determining or applying the Reference Tariff Policy which applies on or after 1 January 2011; or

(D) otherwise be taken into account directly or indirectly by the Relevant Regulator in performing any of its functions under the Code.

(iii) [Deleted]

(b) For the purposes of the Fixed Principles referred to in clause 7.13 of this Access Arrangement, the Fixed Period is until 31 December 2031.

Submissions

978. Alinta has submitted that "DBP is proposing to include as a Fixed Principle that, during the period commencing on 1 July 2005 and ending on 31 December 2015, revenue earned by it from the sale of full haul services that is in excess of that which would have been earned had those services been priced at the prevailing reference tariff (and revenue from other non-full haul services) not be taken into account when setting the R1 Reference Tariff. Alinta considers that this Fixed Principle has no application to the setting of the reference tariff for the proposed R1 Reference Service, and that it is critical that the Fixed Principle only be retained if at least a T1 Reference Service, which is substantially the same as the T1 Reference Services in the 2005 Access Arrangement, is offered in the revised Access Arrangement for the period 2011-2015, and that the Fixed Principle must only apply to the relationship between the T1 Reference Tariff (as properly priced under the NGR) and the tariff under the 2004 Contractual Arrangements."[490]

Considerations of the Authority

979. The Authority considers that the fixed principles set out in the proposed revised access arrangement are consistent with the provisions of the NGR dealing with determining the value of the capital base and with determining reference tariffs. As such, the Authority does not have any concerns with these fixed principles being included in the access arrangement.

980. The Authority considers that the concerns expressed by Alinta arise from a misreading of the fixed principle under clause 13(a)(ii) of the proposed revised access arrangement. The fixed principle is not limited to or by the type or nature of the service. The Authority interprets this fixed principle as preventing the Authority taking into account now or in a future determination any difference between revenues actually earned and revenues that might otherwise have been earned if services were sold at the reference tariff. This fixed principle is consistent with the scheme of regulation established by the NGL and NGR which establishes reference tariffs on the basis of forecasts of costs. Under this scheme of regulation, the Authority is not concerned with actual revenues achieved by DBP.

490 Alinta Pty Limited, 9 July 2010.

Terms and Conditions for Reference Services

Regulatory Requirements

981. In addition to specifying the reference tariff for each reference service, a full access arrangement proposal must specify the other terms and conditions on which the reference service will be provided (rule 48(1)(d)).

982. The NGR do not specify particular requirements for the terms and conditions to apply for each reference service. However, the terms and conditions must be consistent with the national gas objective and rule 100 of NGR.

983. The Authority has a discretion to withhold its approval of the proposed terms and conditions if, in its opinion, a preferable alternative exists that:

- complies with applicable requirements of the Law; and
- is consistent with applicable criteria (if any) prescribed by the Law.

DBP's Proposed Revisions

984. Appendix 1 of the proposed revised access arrangement contains proposed terms and conditions for the R1 Service ("proposed revised terms and conditions").

985. The proposed revised terms and conditions comprise various changes to the terms and conditions included in the 2005 to 2010 access arrangement that DBP advises are in the nature of:

- changes of expression (i.e. "administrative/ drafting/ grammatical");
- changes to be more practical (i.e. "what works in practice"); and
- changes to establish different characteristics of the R1 Service from the reference services under the 2005 to 2010 access arrangement.[491]

986. Substantive proposed revisions to the terms and conditions of the 2005 to 2010 access arrangement, which apply to the T1 Service, include the following.[492]

- A specific term that deems the quantity of gas delivered to the BEP inlet point to be no more than the BEP inlet point capacity (proposed revised terms and conditions, clause 2.6).
- A change in the characteristics of the reference service (from the T1 Service under the current access arrangement) in respect of treatment under the curtailment plan and treatment under the nominations plan (proposed revised terms and conditions, clause 3.2).

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491 DBP, 14 April 2010, Supporting submission #5: Terms and conditions comparison.

492 For the terms and conditions of the 2005 to 2010 access arrangement refers to: Economic Regulation Authority, 26 June 2008, Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, Appendix 1 Part A (T1 Service Terms and Conditions). Reprinted 22 January 2010, incorporating corrigenda of notice dated 22 January 2010.

- Removal of provisions relating to the use of spot capacity (2005 to 2010 terms and conditions, clause 3.5).
- Provision of options for the shipper to renew the contract for two terms of five years, rather than two terms of one year under the current terms and conditions (proposed revised terms and conditions, clause 4.3).
- A requirement that the shipper provides 30 months notice for exercise of an option to renew the contract, rather than three months under the current terms and conditions (proposed revised terms and conditions, clause 4.5).
- Inclusion in the terms and conditions of an obligation of a shipper to pay capacity related transmission charges in certain events where the operator refuses to deliver gas (proposed revised terms and conditions, clauses 5.6 and 5.9).
- Inclusion of more detailed terms relating to the shipper's obligation to pay for system use gas (proposed revised terms and conditions, clause 5.10).
- Inclusion of additional rights of the operator to refuse to deliver or receive gas in circumstances of emergencies (proposed revised terms and conditions, clause 5.11).
- Inclusion of obligations on the shipper to have gas installations and appliances inspected in accordance with the *Gas Standards Act 1972 (WA)* (proposed revised terms and conditions, clause 5.12).
- Inclusion of more detailed terms relating to:
  - operation of multi-shipper agreements at inlet and outlet points (proposed revised terms and conditions, clauses 6.4 and 6.5);
  - design and installation of inlet stations, inlet point connection facilities, and outlet stations (proposed revised terms and conditions, clauses 6.6, 6.7, and 6.8);
  - treatment of notional gate points for delivery of gas to sub-networks, and the design and installation of gate stations (proposed revised terms and conditions, clause 6.10 and 6.11);
  - maintenance charges for inlet stations, outlet stations and gate stations (proposed revised terms and conditions, clause 6.12); and
  - allocation/scheduling of daily nominations (proposed revised terms and conditions, clauses 8.9 and 8.10).
- Removal of terms relating to:
  - nominations for aggregated services (2005 to 2010 terms and conditions, clauses 8.15 and 8.16).
  - the use of a full haul service for delivery of gas at an outlet point upstream of compressor station 9 (2005 to 2010 terms and conditions, clause 8.18).
- A change in terms:
  - for the notification of imbalances to the shipper (proposed revised terms and conditions, clause 9.4);
  - dealing with accumulated imbalances in excess of the accumulated imbalance limit and hourly peaks in excess of hourly peaking limits (proposed revised terms and conditions, clauses 9.5 and 10.3);

  - dealing with the cashing out of imbalances (proposed revised terms and conditions, clause 9.9); and
  - relating to the consequences of exceeding the hourly peaking limit (proposed revised terms and conditions, clause 10.3).

- Removal of terms relating to an outer hourly peaking limit and permissible peaking excursion (2005 to 2010 terms and conditions, clause 10.4 and clause 10.7).
- Inclusion of additional gas parameters in metering requirements (proposed revised terms and conditions, clause 15.4).
- Inclusion of additional terms for providing notice of curtailment (proposed revise terms and conditions, clause 17.6).
- Changes to terms relating to the priority of curtailment of services (proposed revised terms and conditions, clause 17.9).
- Changes to terms relating to apportionment of a shipper's curtailments across outlet points of curtailment of services (proposed revised terms and conditions, clause 17.10).
- Inclusion of additional terms for assignments (proposed revised terms and conditions, clause 25).
- Removal of terms for a general right of relinquishment by a shipper (2005 to 2010 terms and conditions, clause 26).
- Removal of terms for the operator to carry out functions as a broker in the transfer of contracted capacity (2005 to 2010 terms and conditions, clauses 27.11 and 27.12).
- Inclusion of additional exceptions to requirements for confidentiality of information (proposed revised terms and conditions, clause 28.2).
- Removal of terms requiring that the operator procure an audit of compliance with the undertakings to the ACCC under section 87B of the *Trade Practices Act 1974* (2005 to 2010 terms and conditions, clause 28.10).
- Removal of certain warranties of the operator and DBNGP Trustees to the shipper (2005 to 2010 terms and conditions, clauses 30.1(a)(i) and 30.4).
- Removal of provisions for the shipper to require the operator to provide information on planned expansions in capacity of the DBNGP (2005 to 2010 terms and conditions, clause 31(b)).
- Removal of a non-discrimination clause relating to the provision of information by the operator to shippers, and treating all shippers on an arms' length basis (2005 to 2010 terms and conditions, clause 45).
- Removal of terms limiting liability of the DBNGP Trustee (2005 to 2010 terms and conditions, clause 47).

Submissions

987. Submissions from interested parties that comment on provisions of the proposed revised terms and conditions are addressed below under "considerations of the Authority".[493]

988. Some submissions made to the Authority identify minor typographical and drafting matters in the terms and condition. Given the nature of these items, the Authority has not specifically addressed these as part of its considerations below.

Considerations of the Authority

989. Consistent with its decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, part haul P1 Service and back haul B1 Service as reference services the Authority requires that the proposed revised access arrangement be amended to include relevant terms and conditions for these reference services.

990. The following sections of this draft decision set out the Authority's assessment of clauses of the proposed revised terms and conditions where material revisions have been made, with this assessment made on the premise that the proposed revised terms and conditions will form the basis of terms and conditions for the T1, P1 and B1 reference services.

991. In its assessment of the proposed changes to the terms and conditions, the Authority has considered matters including :

- the rationale for variations to the proposed terms and conditions from those established under existing access contracts for pipeline services (i.e. full haul, part haul and back haul services) negotiated with shippers;
- issues raised by existing and prospective shippers with the existing terms and conditions and with proposed revisions to those terms and conditions;
- the relevance and appropriateness of the terms and conditions to amend the reference services required by the Authority (i.e. the T1, P1 and B1 Services);
- operational and practical considerations in the operation of the pipeline;
- a balancing of interests between DBP and users, including consideration of common principles of contracting; and
- whether changes in expression of certain terms achieve DBP's expressed intention and whether these changes may have other unintended consequences.

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[493] Alinta Pty Ltd, submission of 9 July 2010; Verve Energy, submission of 9 July 2010; Rio Tinto, submission of 20 July 2010; and BHP Billiton, submission of 9 July 2010.

992. DBP has proposed numerous revisions to the proposed revised terms and conditions on the basis of "administrative/ drafting / grammatical" reasons. Unless otherwise specified in this draft decision, the Authority is satisfied that these revisions are intended to and do improve the overall drafting of the terms and conditions and therefore accepts all the revisions made for these reasons, subject to the amendments specified in the following sections of this draft decision.[494]

Interpretation provisions (clause 1)

993. Clause 1 of the proposed revised terms and conditions sets out the definitions of terms used under the contract. DBP proposes changes to the definitions of terms and submits that the changes are either to simplify drafting, in response to practical experience, or are reflective of the type of service that is the proposed R1 Service.

994. The Authority considers that several of the changes to definitions of terms should be amended to comply with the requirements of the NGR. The Authority's determinations on these particular terms are set out as follows.

"B1 Service"

995. DBP proposes to insert a new definition for the term "B1 Service" under clause 1 of the proposed revised terms and conditions and submits that the proposed interpretation works better in practice than the previous interpretation.

> ***B1 Service*** means a Back Haul service which, under the terms of a contract for the Back Haul Service, is specified to rank equally to a R1 Service in the Curtailment Plan.

996. The Authority notes that the reference to "Back Haul Service" in DBP's proposed interpretation is not defined and the proposed replacement wording does not make sense.

997. Having regard to the Authority's decision to require amendments to the proposed revised access arrangement to include a full haul T1 Service, the Authority is of the view that the definition of the B1 Service should be the same as, or cross-reference, the description of the B1 service (as a reference service) in the access arrangement.

Required Amendment 16

The term "B1 Service", under clause 1 of the proposed revised terms and conditions should be amended to be the B1 Service described as a reference service in the access arrangement, amended as required by this draft decision.

[494] DBP, 14 April 2010, Confidential supporting submission # 5: Terms and Conditions Comparison, Explanation of Terms and Conditions for the R1 service, pages 4 -21. A public version of this submission is available at: www.erawa.com.au

998. A number of users indicated in submissions that the definition of "B1 Service" was inconsistent with the curtailment plan in Schedule 6 of the proposed terms and conditions.[495]

999. In its response to these third party submissions, DBP submitted that it is prepared to replace the existing proposed words *"is specified to rank equally to a R1 Service in the Curtailment Plan"* with the words *"with priority as set out in the Curtailment Plan"*.

1000. The Authority has considered the curtailment plan in Schedule 6 of the proposed revised terms and conditions and the curtailment priority of the B1 Service at paragraph 1589 and following of this draft decision.

"Capital Cost of the Expansion"

1001. DBP proposes to add a new term "capital cost of the expansion" to clause 1 of the proposed revised terms and conditions. This term is defined as "in relation to any expansion, the costs, including all consultants' fees of the design, engineering, procurement, construction, installation, pre-commissioning and commissioning, of the expansion".

1002. Rio Tinto observes that the term "capital cost of the expansion" is not used in the proposed terms and conditions.

1003. In response to Rio Tinto's submission, DBP submits it would be prepared to delete this term from the proposed terms and conditions.

1004. In view of the apparent redundancy of the term "capital cost of the expansion", the Authority requires the term "capital cost of the expansion" to be deleted from clause 1 of the proposed revised terms and conditions.

Required Amendment 17

The term "Capital Cost of the Expansion" and the definition of this term should be deleted from clause 1 of the proposed revised terms and conditions.

"Contracted Firm Capacity"

1005. DBP proposes changes to the term "contracted firm capacity" to delete references to the T1, B1 and P1 Services and to replace these references with a reference to the "R1 Contract or any contract for a firm service". DBP submits that this change is in recognition of the type of service that is the R1 Service.

[495] Alinta Pty Ltd, submission of 9 July 2010; Verve Energy, submission of 9 July 2010.

1006. Rio Tinto submits that the definition of "contracted firm capacity" needs to continue to include T1 capacity to protect the rights of a shipper which has both T1 and R1 capacity (for example, clauses 5.3(g) and 8.9(d) of proposed revised terms and conditions).[496] Rio Tinto further submits that this is a significant commercial issue as, if it requires new capacity in the near future, it is likely that it would have both old T1 and new capacity. Rio Tinto asks that the terms and conditions be modified to clarify how they operate in such circumstances.

1007. In response to Rio Tinto's submission, DBP refers to the information provided in its response to third party submissions on the proposed changes to delete the term "T1 service" and clauses 8.15 and 8.16 from the existing terms and conditions for the T1 Service, which deal with nominations at an inlet or outlet point for which the shipper does not have contracted capacity or does not have sufficient contracted capacity and that rely on the definition of contracted capacity.

1008. The Authority has considered DBP's proposed changes to delete the term "T1 service" at paragraph 1033 and following of this draft decision. Similarly, the Authority has considered DBP's proposal to delete clauses 8.15 and 8.16 at paragraph 1220 and following.

1009. Consistent with these considerations and the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include the T1 Service, P1 Service and B1 Service as reference services, the Authority believes that the term "contracted firm capacity" should have the same meaning as the term "contracted firm capacity" in the existing terms and conditions.

Required Amendment 18

Clause 1 of the proposed revised terms and conditions should be amended to include the term "Contracted Firm Capacity" with the same meaning as the term "Contracted Firm Capacity" in the existing terms and conditions.

"Force Majeure"

1010. DBP proposes changes to the term "Force Majeure" under clause 1 of the proposed revised terms and conditions, indicating that the changes are for reasons of drafting expression and what works in practice. The changes comprise amendments to the definition of *force majeure* to:

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496 Proposed clause 5.3(g) states that the operator may refuse to receive gas from the shipper *"to the extent that the Receipt of that Gas for a Gas Day at an Inlet Point is in excess of the aggregate of the following in respect of that Inlet Point for that Gas Day all of the Shipper's Contracted Capacity; if the Operator considers as a Reasonable and Prudent Person that to Receive such Gas would interfere with other shippers' rights to their Contracted Firm Capacity"*.

Proposed clause 8.9(d) states: *"The scheduled Capacity Services in respect of the Shipper's Daily Nomination for R1 Service may exceed the Shipper's Total Contracted R1 Capacity across all Inlet Points by a quantity of Gas which is to be Delivered for the purpose, or which would have the effect, of bringing the Shipper's Accumulated Imbalance within the Accumulated Imbalance Limit unless the Operator considers as a Reasonable and Prudent Person that to Deliver such gas would interfere with other shippers' rights to their Contracted Firm Capacity"*.

- include an 'insolvency event'; and
- remove 'any other matters reasonably beyond the control of a party'.

1011. Alinta and Verve Energy each submit that the amendment to include an insolvency event in relation to a third party supplier of the operator should be deleted. They submit that the operator should be able to, and be required to, take steps in those circumstances to ensure its ability to perform its obligations under the contract is not affected.

1012. In its response to third party submissions, DBP submits that:

- the substantive part of the definition remains unchanged – force majeure must be an event or circumstance not within a party's control and which the party is not able to prevent or overcome, acting as a reasonable and prudent person;
- the only change to the definition has been the addition of a further example, but this does not change the fact that the event or circumstance must still meet the substantive part of the definition;
- due to the nature of the markets in Western Australia for certain goods required by the operator, the operator, acting as a reasonable and prudent person, may not always be in a position to ensure it can perform its obligations under the contract if a critical third party supplier is subject to an insolvency event; and
- accordingly, the proposed change to the definition of force majeure should be accepted.

1013. The Authority has considered Alinta and Verve's views. However, the Authority is satisfied that the principles of force majeure remain unchanged by DBP's proposed changes to the definition.

"Major Works"

1014. DBP proposes changes to the term "major works" under clause 1 of the proposed revised terms and conditions to include planned maintenance. DBP submits that the proposed change works better in practice.

> Major Works means:
>
> <u>(a) any Planned Maintenance; and</u>
>
> <u>(b)</u> any enhancement, expansion, connection, pigging or substantial work that the Operator needs to undertake on the DBNGP and that:
>
> (i) cannot reasonably be scheduled at a time when it will not affect Gas Transmission Capacity; and
>
> (ii) by its nature or magnitude would require a Reasonable and Prudent Person to wholly or partially reduce Gas Transmission Capacity.

1015. "Planned maintenance" is defined in clause 1 of the proposed terms and conditions as "maintenance of the DBNGP which is scheduled in advance and of which the shipper is given reasonable, and in any event not less than three gas days, written notice"; and remains unchanged from the interpretation in the existing 2005 to 2010 terms and conditions.

1016. Alinta and Verve Energy each submit that the inclusion of planned maintenance in the definition of major works means that planned maintenance is an additional exemption from the operator being liable for curtailing more than two per cent each year under clause 17.3 of the proposed terms and conditions. Alinta and Verve Energy both submit that the definition of "major works" should exclude "planned maintenance".

1017. In its response to third party submissions, DBP submits that the intention of the change was to ensure that work, such as overhauls of turbines, would be covered by major works, reflecting what occurs in practice. DBP maintains that the proposed drafting change should be accepted.

1018. Having regard to the submissions of interested parties, including the response of DBP, the Authority considers that DBP has not provided adequate justification for the proposed change, which in the Authority's view is likely to result in an additional exemption from the operator being liable for curtailing more than two per cent each year under clause 17.3 of the proposed terms and conditions. The Authority is of the view that the most appropriate and practical way of addressing the concerns raised by Alinta and Verve will be to reject the proposed change to exclude planned maintenance in the definition of the term "major works".

Required Amendment 19

The term "Major Works", under clause 1 of the proposed revised terms and conditions should be amended to exclude planned maintenance.

"Overrun Gas"

1019. DBP proposes changes to the term "overrun gas" and submits that the changes are either administrative or to make the term more appropriate for the proposed R1 Service. The Authority has, at paragraph 987 of this draft decision, accepted the administrative changes.

1020. The changes relating to the appropriateness of the term are as follows:

> Overrun Gas means, for a particular Gas Day and for a particular shipper, Gas Received by that shipper (across all Outlet Points) less the aggregate of the quantities of Contracted Capacity across all of that shipper's Capacity Services (including ~~T1 Services and any Capacity under Spot Transactions~~R1 Service) (across all Outlet Points) on that Gas Day and, if the preceding calculation produces a negative result, Overrun Gas for that Gas Day equals zero.

1021. Rio Tinto submits that the definition of "overrun gas" should continue to recognise T1 capacity.

1022. Consistent with these considerations and the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed revised terms and conditions for the T1 Service should be substantially the same as the existing terms and conditions for the T1 Service. Accordingly, the Authority considers that the term "overrun gas" should have the same meaning as the term "overrun gas" in the existing 2005 to 2010 terms and conditions.

Required Amendment 20

Clause 1 of the proposed revised terms and conditions should be amended to include the term "Overrun Gas" with the same meaning as the term "Overrun Gas" in the existing terms and conditions for the T1 Service.

"Previous Verification"

1023. DBP proposes changes to the term "previous verification" under clause 1 of the proposed revised terms and conditions to replace the words "measuring the quantity of gas accurately" with the term "accurate". DBP submits that this change is to simplify the drafting.

1024. Alinta and Verve Energy each note that the term "accurate" is not defined in clause 1 of the proposed terms and conditions and that the definition for this term should be consistent with the definition that exists in the existing 2005 to 2010 terms and conditions.

1025. In its response to third party submissions, DBP submits that it proposes to include the following definition for "accurate" in clause 1 of the proposed terms and conditions:

> ***Accurate*** means, with respect to any measurement of a quantity of Gas, that the measurements is inaccurate to a lesser extent than the relevant limit prescribed by clause 15.13(a)(i) or 15.13(a)(ii) (as the case may be).

1026. The Authority believes that the exclusion of the term "accurate" from clause 1 of the proposed terms and conditions is an administrative oversight and is satisfied that DBP's proposal to include the term "accurate" as set out in its response to third party submissions addresses this oversight with one minor amendment set out below.

Required Amendment 21

Clause 1 of the proposed revised terms and conditions should be amended to include the term *"Accurate"* which means *"with respect to any measurement of a quantity of Gas, that the measurement is inaccurate to a lesser extent than the relevant limit prescribed by clause 15.13(a)(i) or 15.13(a)(ii), as the case may be"*.

"Related Body Corporate" and "Related Entity"

1027. DBP proposes changes to the term "Related Body Corporate" under clause 1 of the proposed revised terms and conditions and a new term "related entity". DBP submits that these changes are to simplify the drafting and for the reason that this wording works better in practice in the case of the term 'Related Entity'.

> ***Related Body Corporate*** has the meaning given <u>in the Corporations Act as at the Execution Date</u> ~~to that expression in the Corporations Act~~.
>
> <u>***Related Entity*** has the meaning given to that expression in the Corporations Act as at the Execution Date.</u>

1028. Alinta and Verve Energy each submit that the definitions incorporating terms as defined in the Corporations Act should be those terms as they apply from time-to-time, and not as limited to a point in time. Limiting the definition to a point in time is difficult to administer for the shipper and operator.

1029. In its response to third party submissions, DBP submits that the T1 SSCs (SSCs) define these terms by reference to the version of the Corporations Act at a fixed point in time. Furthermore, in DBP's experience with the SSCs, the definition to a point in time is not difficult to administer for either party.

1030. The Authority has considered submissions and agrees that limiting the definition to a point in time is potentially more difficult to administer for the shipper and DBP and the standard convention in relation to definitions in contracts is to refer to legislation as being from time-to-time.

Required Amendment 22

The terms "Related Body Corporate" and "Related Entity", under clause 1 of the proposed revised terms and conditions should be amended so as they apply to the definitions in the Corporations Act as defined from time-to-time, and not as limited to a point in time.

"Retail Market Rules"

1031. DBP proposes changes to the term "Retail Market Rules" under clause 1 of the proposed revised terms and conditions, indicating that the changes are in the nature of administrative/grammatical changes.

> ***Retail Market Rules*** means the retail market rules that govern<u>, or will govern when operative</u>, the retail gas market in Western Australia.

1032. Alinta and Verve Energy both submit that the Retail Market Rules are already operative. In its response to third party submissions, DBP submits that it does not object to the proposed wording "or will govern when operative" being deleted from the definition of "retail market rules". Accordingly, the Authority requires this amendment to be made to this term under clause 1 of the proposed terms and conditions.

Required Amendment 23

The term "Retail Market Rules", under clause 1 of the proposed revised terms and conditions should be amended to mean *"the retail market rules that govern the retail gas market in Western Australia"*.

"T1 Service"

1033. DBP proposes to delete the term "T1 service" from clause 1 of the proposed revised terms and conditions.

1034. Alinta and Verve Energy both note that the T1 Service is still a term used in the proposed terms and conditions, including in the curtailment plan, and hence a definition of the T1 Service should be retained.

1035. In its response to third party submissions, DBP submits that it does not object to a definition of "T1 service" for the purposes of references in the proposed terms and conditions for the R1 Service (the 'R1 Contract') to T1 services being included. DBP proposes the definition for "T1 service" to be "the service known as the T1 Service in the Standard Shipper Contract", with "Standard Shipper Contract" meaning "the contract of that nature required to be made available on DBP's website".

1036. The Authority concurs with the submissions of Alinta and Verve Energy that, to the extent the proposed terms and conditions make reference to the T1 Service (such as for example, in the curtailment plan), the terms and conditions should define the T1 Service.

1037. Consistent with the Authority's decision, however, to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed revised terms and conditions for the T1 Service should be substantially the same as the existing terms and conditions for the T1 Service. Accordingly, the Authority believes that the term "T1 Service" should be maintained in clause 1 of the proposed revised terms and conditions with the same definition as the existing terms and conditions, which includes both a T1 Service being provided under the Standard Shipper Contract and a T1 Service being provided under the terms of the access arrangement.

Required Amendment 24

Clause 1 of the proposed revised terms and conditions should be amended to have the same meaning as the term "T1 Service" in the existing terms and conditions.

"Tp Service"

1038. DBP proposes to add a new term "Tp service" to clause 1 of the proposed revised terms and conditions, which is defined to mean an "other reserved service". DBP submits that this change is for practical reasons.

1039. Alinta and Verve Energy both submit that the definition does not actually identify or describe the Tp service itself, which should be identified by its essential characteristics and by the fact it is only available to Stage 5A shippers. Alinta and Verve Energy both note that the terms "firm service" and "other reserved service" have been retained when it is doubtful that any shipper has contracted for such services.

1040. In its response to third party submissions, DBP submits that a more detailed definition of "Tp service" is not relevant or necessary for the purposes of administering or interpreting the proposed R1 Service. Moreover, the Tp Service is not available to prospective shippers. Hence, DBP submits that no further change is warranted. In relation to the comments concerning the terms "firm service" and "other reserved service", DBP submits that:

- these terms are necessary definitions as they are referenced in the curtailment plans that DBP has agreed to with shippers under existing contracts; DBP must have consistent curtailment plans for all of its shippers otherwise it will place itself in breach of contract; and
- a third party is not best placed to comment on whether the operator has contracted with other parties for firm services or other reserved services.

1041. The Authority has considered the submissions and considers that clause 48(1)(b) of the NGR requires that the definition of the Tp service should be, but is currently not sufficient to identify the characteristics of the service.

Required Amendment 25

The term "Tp Service", under clause 1 of the proposed revised terms and conditions should be amended to identify the characteristics of the service.

General provisions (clause 2)

1042. Clause 2 of the proposed revised terms and conditions contains general provisions for the construction of the contract. In addition to changes to address drafting expressions, DBP proposes changes to include new provisions relating to the interpretation of inlet points (clause 2.6) and the access regime (clause 2.7). DBP submits that the reason for these new provisions is that they will work better in practice.

Clause 2.5 – Ring fencing requirements

1043. Proposed revisions to clause 2.5(e) require the operator to ensure that the system operator complies with the ring fencing arrangements of section 4 of the National Third Party Access Rules for Natural Gas Pipeline Systems. Alinta and Verve Energy each submit that this clause should refer to the ring fencing requirements under Part 2 of Chapter 4 (Structural and operational separation requirements (ring fencing)) of the National Gas Access (Western Australia) Law. In its response to third party submissions DBP concurs that this is appropriate. The Authority requires clause 2.5(e) to be amended accordingly.[497]

> **Required Amendment 26**
>
> Clause 2.5(e) should be amended to make reference to *"Part 2 of Chapter 4 of the National Gas Access (Western Australia) Law"* instead of "section 4 of National Third Party Access Rules for Natural Gas Pipeline Systems".

Clause 2.6 – Interpretation of inlet points

1044. DBP has included a new clause 2.6 to introduce a specific term that deems the quantity of gas delivered to the "BEP inlet point" to be no more than the "BEP inlet point capacity". Both Alinta and Verve Energy have questioned why this is the case. In its response to third party submissions, DBP has provided the Authority with additional information on the proposed BEP arrangements, indicating that the new clause 2.6 was necessary to enable DBP to comply with contractual obligations relating to the lease of the BEP Capacity.

1045. The Authority is of the view that it is not appropriate for gas deliveries made by or on behalf of users to be deemed to be of a certain amount irrespective of actual quantities just so as to enable DBP to meet its contractual obligations in respect of a lease of capacity in the BEP entered into in full knowledge of the existing access arrangement.

> **Required Amendment 27**
>
> The proposed revised terms and conditions should be amended to delete clause 2.6.

Clause 2.7 – Access regime and regulator's requirements as laws

1046. DBP has added a new clause 2.7 to clarify that the access regime and regulator's requirements are to be treated as laws under the contract.

> 2.7 To avoid doubt, any provisions of the Access Regime and any requirements of the Regulator that prevail by force of law over an inconsistent clause of this Contract are Laws for the purposes of this Contract, but neither Party may seek to procure an

497 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

> amendment to an access arrangement under the Access Regime if the purpose for which such amendment is sought is to affect materially and adversely any of the other Party's rights and obligations under this Contract that are not general rights and obligations applicable to all shippers.

1047. Alinta and Verve Energy both submit that amendments to the access arrangement must not be sought to materially and adversely affect any of the other party's rights and obligations under the contract regardless of their nature. Hence, clause 2.7 should be amended to remove the words "that are not general rights and obligations applicable to all shippers".

1048. Rio Tinto submits that the Authority should consider whether the proposed contractual restriction on the parties' regulatory conduct is appropriate.

1049. In response to Alinta and Verve Energy's submissions, DBP submits that the operator should not be prevented from seeking amendments to an access arrangement on commercial grounds, which are non-discriminatory between shippers, because it may have a material and adverse impact on shippers. The access regime enables shippers to lodge an objection with the regulator in relation to any such amendments.

1050. The Authority is of the view that the second part of the proposed new clause dealing with amendments to an access arrangement is unnecessary. The Authority agrees with Rio Tinto that it is inappropriate to deal with parties' rights to seek amendments to other access arrangements in the DBNGP's terms and conditions. It is difficult to see how such a provision would be enforced and, in any event, any proposed amendment to an access arrangement will be dealt with under Divisions 10 or 11 of the NGR.

Required Amendment 28

Clause 2.7 of the proposed revised terms and conditions, in relation to the access regime and the regulator's requirements as laws should be amended to insert a full stop after 'Contract' in the 3rd line and delete the balance of the clause.

Capacity service (clause 3)

1051. Clause 3 of the proposed revised terms and conditions establishes terms for the capacity service under the contract. Under clause 1 of the proposed terms and conditions, the "capacity service" is any service offered by DBP on the DBNGP by which access to gas transmission capacity is provided.

1052. DBP proposes several changes to clause 3 and submits that these changes are either in recognition of the type of service that is the R1 Service, are for practical reasons, or are grammatical/administrative changes.

1053. The changes in recognition of the type of service are:

- the introduction of the R1 Service, to replace the T1 Service (proposed clause 3.1);

- a change in the characteristics of the reference service in respect of the reliability of the service, treatment under the curtailment plan, and treatment under the nominations plan (proposed clause 3.2); and
- the removal of provisions relating to the use of spot capacity (clause 3.5 of the 2005 to 2010 terms and conditions).

Clause 3.2 – Capacity service

1054. Clause 3.2 of the proposed revised terms and conditions defines the capacity service that is the subject of the terms and conditions.

1055. Proposed changes to clause 3.2 change the relevant service from the T1 Service to the R1 Service, and the treatment of the service under the curtailment plan and nominations plan. The proposed changes to clause 3.2 are set out as follows.

3.2 Capacity Service

(a) The ~~T~~ R1 Service is the ~~Full Haul~~ Gas transportation service ~~provided under this Contract~~ which gives the Shipper a right, ~~subject to the terms and conditions of this Contract, to~~ of access ~~capacity of the DBNGP~~ to Gas Transmission Capacity and which, (subject, in all cases, to clauses 8.15 and (sic?) 17.9):

~~(i) can only be Curtailed in the circumstances specified in clause 17.2;~~

(i) is treated the same in the Curtailment Plan as all other shippers (?) with a ~~T~~ R1 Service, ~~including the T~~a P1 Service ~~under the Standard Shipper Contract~~ or a B1 Service, and in the order of priority with respect to other Types of Capacity Service set out in clause 17.9; and

(ii) is treated the same in the Nominations Plan as all other shippers (?) with a ~~T~~ R1 Service, ~~including the T~~a P1 Service ~~under the Standard Shipper Contract~~or a B1 Service, and in the order of priority with respect to other Types of Capacity Service referred to in clause ~~8.~~9.8.8.

(b) R1 Capacity is the average amount of Gas Transmission Capacity, estimated by the Operator in accordance with Good Gas Industry Practice, through Kwinana Junction on each Gas Day in the month of January of each year with the most critical compressor unit upstream of Kwinana Junction off-line. ~~Operator acknowledges and agrees:~~

~~(i) Tranche 1 Capacity in the DBNGP comprises the amount of Gas Transmission Capacity which lies between zero and the T1 Cut off;~~

~~(ii) the T1 Cut-off is the amount of Gas Transmission Capacity at which the probability of supply for the next GJ of Gas to be transported in the DBNGP is 98% for each Period of a Gas Year;~~

~~(iii) whenever there is a material change (other than a short term change) in the configuration of the DBNGP which will or might change the probability of supply at the T1 Cut-off for any or all Periods in a Gas Year, Operator, acting as a Reasonable And Prudent Person, shall undertake a re-determination in accordance with clause 3.2(b)(ii) of the T1 Cut-off for each Period in which the T1 Cut-off has changed; and~~

~~(iv) acting as a Reasonable and Prudent Person, Operator shall ensure that the sum of:~~

~~(A) T1 Service (including under this Contract) which it has contracted to provide to Shipper and all other shippers; and~~

~~(B) Alcoa's Exempt Capacity, does not materially exceed the amount of T1 Capacity in the DBNGP.~~

~~(c) Shipper acknowledges and agrees that, subject to clause 14, the T1 Service is a Full Haul Service and cannot be:~~

~~(i) Back Haul; or~~

~~(ii) Part Haul.~~

~~(d) In this clause 3.2 probability of supply means the probability that Gas Transmission Capacity in the DBNGP will not, for any reason other than Major Works, fall below a particular cut-off level.~~

~~(e) For the avoidance of doubt, Alcoa's Exempt Capacity is provided by Operator out of Tranche 1 Capacity in the DBNGP.~~

1056. DBP submits that the changes to clause 3.2 of the proposed revised terms and conditions are in recognition of the type of service that is the R1 Service and for what works in practice.

1057. Alinta and Verve Energy both submit the following in relation to clause 3.2 of the proposed revised terms and conditions.

- Clause 3.2(a)(i) is not correct in saying that the R1 Service is treated the same in the curtailment plan as the T1 Service, as the R1 Service is a different type of capacity service and is lower in priority in the curtailment plan than the P1 and B1 Service.
- Clause 3.2(a)(ii) is incorrect as it states that the R1 Service is treated the same in the nominations plan as all other shippers with a R1, P1 or B1 Service, and this is incorrect as the nominations plan is based on the curtailment plan.
- DBP has not provided any support for its quantification methodology for clause 3.2(b), such as the amount of capacity it will capture in addition to the T1 Capacity already captured by the quantification methodology in the existing shipper contracts, what is the likely annual percentage of curtailments (as it is curtailed before T1, P1 and B1) and how much does the average throughput in January vary from the highest and lowest throughput which are dependent on gas demand downstream of Kwinana Junction.
- "Critical" is assumed to mean the most important compressor in maximising gas transmission capacity and this should be clarified.

1058. In its response to third party submissions, DBP submits that in each of the clauses 3.2(a)(i) and 3.2(a)(ii) the words a "P1 Service or a B1 Service" should be deleted.

1059. In response to Alinta and Verve Energy's comment that DBP has not provided any support for its quantification methodology in clause 3.2(b) of the proposed revised terms and conditions for the R1 Capacity, DBP submits that this is explained in 4.7(b) of its supporting submission #3 which states that:

> The means for determining the availability of the service is different to that that has been used to determine the level of availability of the T1 Service proposed by the Operator in the Proposed Revised AA. The methodology for determining

> the availability and reliability of the T1 Service has been based on the probability of supplying to Kwinana Junction with the most critical compressor off line is no longer relevant, given the extensive expansion of the pipeline.[498]

1060. DBP further submits, in its response to third party submissions, that the use of average throughput in January is consistent with the methodology used to calculate the T1 capacity of the pipeline. DBP also submits that the use of the term "critical" is sufficiently certain.

1061. Clause 3.2(b)(iii) of the existing terms and conditions requires DBP to recalculate the maximum capacity of the pipeline whenever it materially changes. Rio Tinto submits that there is no justification for the deletion of clause 3.2(b)(iii) and it removes an important transparency measure.

1062. Clause 3.2(b)(iv) of the existing terms and conditions provides that DBP, acting as a reasonable and prudent person, shall ensure that the sum of the T1 Service which it has contracted to provide to shippers and Alcoa's exempt capacity, does not materially exceed the amount of T1 Capacity in the DBNGP.

1063. Rio Tinto submits that clause 3.2(b)(iv) should not be deleted as:

- it means that DBP will have an incentive to sell too much capacity and to deal with the consequences by pro-rated curtailments;
- DBP will get the benefit of additional revenue but all shippers will pay through reduced reliability; and
- this clause is the commercial underpinning of the entire concept of firm service and its removal is a material commercial risk for both new and incumbent shippers.

1064. The Authority has considered the changes to clause 3.2 in the context of the requirement under this draft decision for the proposed revised access arrangement to include the T1 Service, P1 Service and B1 Service as reference services. Without the change in the reference service to the R1 Service, the changes proposed by DBP to clause 3.2 are unnecessary. Further, the Authority accepts the submission of Rio Tinto in relation to the proposed deletion of clauses 3.2(h)(iii) and 3.2(h)(iv). Accordingly, the Authority requires that clause 3.2 of the proposed revised terms and conditions be amended to be materially the same as clause 2 of the current terms and conditions.

Required Amendment 29

Clause 3.2 of the proposed revised terms and conditions should be amended to be materially the same as clause 2 of the current terms and conditions for the T1 Service.

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[498] DBP, 14 April 2010, Confidential supporting submission #3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au

Spot Capacity (clause 3.5 of the 2005 to 2010 terms and conditions)

1065. DBP proposes not to retain clause 3.5 of the existing terms and conditions for the T1, B1 and P1 Services, which contains provisions for users of these services to have access to spot capacity. Spot capacity means any gas transmission capacity on a gas day for which gas transmission capacity, is, according to DBP, acting in good faith, available for purchase. Clause 3.5 of the existing terms and conditions comprises principles and procedures for users to bid for spot capacity, for DBP to allocate spot capacity to bidding users and for the operator to establish rules governing the market for spot capacity. Clause 3.5 provides an implicit entitlement for the users of the T1, B1 and P1 Services to have access to spot capacity in accordance with the principles and procedures of clause 3.5 and rules established by DBP for the market for spot capacity. The deletion of clause 3.5 from the terms and conditions of the reference services would remove the implicit entitlement of a user of the reference services to obtain spot capacity in accordance with the principles and processes set out in this clause.

1066. In relation to the proposed deletion of provisions allowing for the purchase of spot capacity, Alinta and Verve Energy submit that if provisions for spot capacity are not included in the reference service then there is no clarity as to the terms and conditions upon which spot capacity may be made available in the future.

1067. BHP Billiton (**BHPB**) submits that:

- the removal of clause 3.5 in relation to the spot capacity market could ultimately reduce the ability to trade excess gas;
- shippers who may not have existing access to the spot market, may suffer long lead times in arranging a contract to access spot capacity and therefore miss out on potential sales or purchases; and
- the removal of the provisions relating to spot capacity therefore reduces the effectiveness of a spot gas market and should not be approved.

1068. DBP's response to third party submissions states that the reasons why spot capacity is not required are provided in section 2 of its supporting submission #5 which states that:

- spot capacity is not appropriate for the proposed R1 Service because rule 109 of the NGR prevents the bundling of services together unless it is reasonably necessary to bundle them together; and
- it is not reasonably necessary to bundle the 2 services together as spot capacity can be accessed without the need for another haulage service being in place.[499]

[499] DBP, 14 April 2010, Confidential supporting submission # 5: Terms and Conditions Comparison. A public version of this submission is available at: www.erawa.com.au

1069. In its response to third party submissions, DBP also submits that section 2 of its supporting submission #6 provides the explanation of how access to spot capacity may be obtained. DBP's submission #6 states that if the access request is accepted and all documentation is executed, then the shipper will be given access to the spot market in which case it will not need to make an access request each time it needs spot capacity.[500]

1070. DBP further submits, in its response to third party submissions, the following reasons exist for not including the spot capacity service as a reference service:

- The level of utilisation of the pipeline capacity (which is expected to continue during the access arrangement period) means that spot capacity is not likely to be accessed.
- The terms and conditions of spot capacity (including tariff) as a non-reference service will be the same as if it were part of the reference service because of DBP's non-discrimination obligations.
- Separating spot capacity from the reference service will enable parties who seek interruptible capacity to access such capacity without needing to also access a reference service.
- Creating a separate service will ensure a more efficient allocation of spot capacity across the market.[501]

1071. The Authority agrees with the submissions of interested parties that deletion of clause 3.5 from the terms and conditions of the reference services could potentially result in users of the reference services entering into new contracts losing access to these services under the terms and conditions of the reference service. However, DBP has included the same provisions for access to a spot capacity service in clause 3.6 of the proposed revised access arrangement, with these provisions now applying to all users rather than just those that procure a reference service. Given this, the Authority considers that the deletion of clause 3.5 from the terms and conditions does not materially affect the ability of users to obtain access to spot capacity.

1072. The Authority is also satisfied that the use of spot capacity through processes established by clause 3.5 of the existing terms and conditions is a separate service from the reference services. The Authority does not have any evidence before it to suggest that access to spot capacity would be routinely required as part of the reference services or that access to spot capacity is a necessary or intrinsic element of the reference services. Accordingly, and noting the requirements of rule 109 of the WGR in relation to the funding of services the Authority is of the view that maintenance of clause 3.5 in the terms and conditions for reference services is not necessary for compliance with the requirements and objectives of the NGR.

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500 DBP, 14 April 2010, Confidential supporting submission # 6: Explanation of Queuing Requirements. A public version of this submission is available at: www.erawa.com.au

501 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

Duration of the contract (clause 4)

1073. Clause 4 of the proposed terms and conditions establishes the duration of the contract and includes provisions for the capacity start date, the term of the contract, the option for a shipper to renew a contract, and the ability for a shipper to give notice to DBP to exercise either the first option period or the second option period in relation to the term of the contract.

1074. Proposed changes to clause 4 include:

- options for the shipper to renew the contract for two terms of five years, rather than two terms of one year under the 2005 to 2010 terms and conditions; and
- shippers are required to give 30 months notice for renewal of contracts rather than the existing 3 months.

1075. DBP submits that the proposed changes to clause 4 of the terms and conditions are either in recognition of the type of service that is the R1 Service, to address what works in practice, or are changes of an administrative/grammatical nature.

Clause 4.1 – Capacity start date

1076. Clause 4.1 establishes the capacity start date, which means the date specified in the contract as the date on which the shipper's access to the particular contracted capacity is to start or has started.

1077. The main change to clause 4.1 is that it now includes a provision that provides that requests from the shipper for any amendment to the capacity start date will be considered by DBP, with terms and conditions for any such amendment to be agreed between the parties, having regard to DBP’s circumstances at the time of the request.

1078. DBP submits that the proposed changes to clause 4.1 are either changes due to what works in practice or are changes of an administrative/grammatical nature.

1079. Alinta and Verve Energy submit that there are drafting problems with clause 4.1 of the proposed revised terms and conditions as:

- the terminology is inconsistent between clause 4 and the Access Request Form as the form refers to “Reference Services” and the clause refers to “Capacity”;
- the defined term “Access Request Form”, being the form in Schedule 1 of the terms and conditions, does not specify any dates or link the contract for the R1 Service with the Access Request Form; and
- the date in the Access Request Form, being the date on which the request is made, may not be the date agreed by the operator on which capacity starts.

1080. In its response to third party submissions, DBP’s submits that:

- the Access Request Form will, when completed include the dates on which the R1 Service is to start and end and also state that the R1 Shipper Contract terms and conditions apply to the Reference Service which is being requested;

- Part 8 of the Access Request Form provides the necessary link to the R1 shipper contract terms and conditions;
- to reduce any ambiguity about capacity start and end dates, the words "as the Requested Reference Service Start Date" could be added to the end of the sentence in clause 4.1(a); and
- the definition of "Access Request Form" in clause 1 of the proposed revised terms and conditions be amended to read "means the access request form in the form set out in Schedule 1 entered into between the Operator and the Shipper to which these R1 Terms and Conditions are appended".[502]

1081. Subject to appropriate amendments consequent on the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority will accept the proposed revisions to clause 4.1(a) with the further amendments as outlined in DBP's response to third party submissions together with the further amendment to the definition of "Access Request Form".

Required Amendment 30

Clause 4.1(a) of proposed revised terms and conditions in relation to the capacity start date, should be amended to include the words "as the Requested Reference Service Start Date" at the end of the sentence.

The definition of "Access Request Form" in clause 1 of the proposed revised terms and conditions be amended to read "means the access request form in the form set out in Schedule 1 entered into between the Operator and the Shipper to which these Terms and Conditions are appended".

Clause 4.2 – Term

1082. Clause 4.2 of the proposed revised terms and conditions (corresponding to clause 4.1 in the current terms and conditions) relates to the term of a shipper's contract. The proposed change to clause 4.2 is minor and is as follows.

4.2 Term

(a) Subject to the terms and conditions of this Contract, including clause 4.3, the Capacity End Date is 08:00 hours on the date specified in the Access Request Form ~~as the Capacity End Date~~.

(b) Subject to the terms and conditions of this Contract, this Contract ends on the last of the Capacity End Dates.

1083. DBP submits that the proposed change to clause 4.2 is for practical and administrative reasons.

1084. Alinta and Verve Energy submit, in relation to clause 4.2 of the proposed revised terms and conditions, and as with clause 4.1, that:

502 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

- the defined term “Access Request Form”, being the form in Schedule 1 of the terms and conditions, does not specify any dates or link the contract for the R1 Service with the Access Request Form;
- the date in the Access Request Form, being the date on which the request is made, may not be the date agreed by the operator on which capacity starts; and
- the terminology is inconsistent between clause 4 and the Access Request Form as the form refers to “Reference Services” and the clause refers to “Capacity”.

1085. In its response to third party submissions, DBP’s submits in relation to clause 4.2 of the proposed revised terms and conditions, and as with clause 4.1 of the proposed revised terms and conditions, that:

- the Access Request Form will, when completed, include the dates on which the R1 Service is to start and end and also state that the R1 Shipper Contract Terms and Conditions apply to the Reference Service which is being requested;
- Part 8 of the Access Request Form provides the necessary link to the R1 Shipper Contract terms and conditions;
- to reduce any ambiguity about capacity start and end dates, the words "as the Requested Reference Service Start Date" could be added to the end of the sentence in clause 4.1(a) and the words "as the Requested Reference Service End Date" could be added to the end of the sentence in clause 4.2(b); and
- in relation to the definition of "Access Request Form", DBP submits that this could be amended to read "means the access request form in the form set out in Schedule 1 entered into between the Operator and the Shipper to which these R1 Terms and Conditions are appended".[503]

1086. The Authority considers that the amendment to clause 4.2(b) and to the definition of the “Access Request Form” proposed by DBP in its response to third party submissions modified to remove the reference to R1 addresses the concerns of Alinta and Verve Energy.

Required Amendment 31

Clause 4.2(b) of the proposed revised terms and conditions, in relation to the term (duration of the contract), should be amended to include the words "as the Requested Reference Service End Date" at the end of the sentence.

Clause 4.3 – Option to renew contract

1087. Clause 4.3 of the proposed revised terms and conditions sets out the provisions for a shipper to renew a contract.

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503 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

1088. The proposed change to clause 4.3 of the terms and conditions is the provision of the option for the shipper to renew the contract for two terms of five years, rather than two terms of one year under the 2005 to 2010 terms and conditions.

1089. DBP submits that this change has been made because the proposed amendment works better in practice. The only comment from interested parties on this change was from BHP Billiton who supports the change.

1090. The Authority is satisfied that the change is reasonable.

Clause 4.5 – Notice exercising an option

1091. Clause 4.5 of the proposed revised terms and conditions sets out the period of written notice that a shipper must give DBP if it wishes to exercise an option.

1092. Clause 4.5 of the existing terms and conditions require that a shipper give three months notice to DBP to exercise an option. DBP proposes a change to this clause to require that the shipper provide 30 months notice for the exercising of an option to renew its contract.

4.5 Notice exercising an Option

> Not later than 30 months before the Capacity End Date, the Shipper may give written notice to the Operator that it wishes to exercise an Option. If such notice is not given before such time, the Option lapses and is of no force or effect whatsoever and cannot be exercised and, if the Option is the first of the two Options, the second Option also lapses and is of no force or effect whatsoever and cannot be exercised.

1093. DBP submits that the proposed changes to clause 4.5 of the terms and conditions are either for practical reasons or are administrative/grammatical changes.

1094. BHP Billiton submits that:

- the proposed amendment to clause 4.5, providing that the shipper must give 30 months notice prior to extending the term of its contract, is unreasonable;
- most shippers will not be in a position to make informed decisions as to their transportation needs 30 months in advance; and
- the position in the existing terms and conditions should be amended to provide a longer notice period, however, the relevant notice period should be limited to 12 months.

1095. In its response to third party submissions, DBP advises that it would be prepared to consider reducing the period to 12 months, “as long as the shipper has not in the preceding 18 months rejected a request from DBP to relinquish capacity, so as to enable an expansion to occur”.[504] DBP has not provided an explanation for the inclusion of this additional clause and the Authority, without a satisfactory explanation of the reason for its inclusion, would not approve the additional requirement.

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[504] DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

1096. The Authority has taken the above matters into consideration and is of the view that a period of 12 months is reasonable to require a shipper to give notice that it wishes to exercise an option.

Required Amendment 32

Clause 4.5 of the proposed revised terms and conditions, in relation to a shipper exercising an option to renew its contract, should be amended to state "not later than 12 months before the capacity end date, a shipper may give written notice to the operator that it wishes to exercise an option".

Clause 4.6 – First option period; and Clause 4.7 – Second option period

1097. Clauses 4.6 and 4.7 of the proposed revised terms and conditions incorporate changes from the existing terms and conditions as follows.

First Option Period

4.6 If the Shipper gives a notice in accordance with clause 4.5 exercising the first ~~option given to it under clause 4.3~~, Option, then the Period of Supply for the Original Capacity under this Contract ~~will be extended for a period of 1 year~~ is extended to 08:00 hours on the date occurring 20 years after the Capacity Start Date and:

(a) the Capacity End Date for the Original Capacity (as defined in clause ~~4.14~~.2(a)) is amended to 08:00 hours on that date;

(b) the extension of the Period of Supply for the Original Capacity is subject to the condition that, in the period between the giving of a notice under clause 4.5 and 08:00 hours on the date occurring 15 years after the Capacity Start Date, this Contract is not validly terminated for the Shipper's default (within the meaning of clause 22.1); and

(c) this clause 4.6 (relating to the exercise of the first Option) ~~will have~~ has no effect after 08:00 hours on the date ~~date originally specified in the Access Request Form as~~ occurring 15 years after the Capacity ~~End~~ Start Date.

4.7 Second Option Period

If the Shipper has exercised the first option under clause 4.3 Option and gives a notice in accordance with clause 4.5 exercising the second ~~option given to it under clause 4.3~~ Option, then the Period of Supply for the Original Capacity under this Contract ~~will be extended for a period of another year~~ is extended to 08:00 hours on the date occurring 25 years after the Capacity Start Date and:

(a) the Capacity End Date for the Original Capacity (as amended by the previous operation of clause 4.6(a)) is amended to 08:00 hours on that date; and

(b) the extension of the Period of Supply is subject to the condition that, in the period between the giving of the notice under clause 4.5 and 08:00 hours on the date occurring 20 years after the Capacity Start Date, this Contract is not validly terminated for the Shipper's default (within the meaning of clause 22.1); and

(c) clauses 4.3, 4.4, 4.5 and this clause 4.7 (all relating to the exercise of the second Option) ~~will have~~ has no effect after 8:00 hours on the date ~~that is one~~

~~year~~ occurring 20 years after the ~~date that was originally specified in the Access Request Form as the~~ Capacity ~~End~~ Start Date.

1098. DBP submits that the changes to clauses 4.6 and 4.7 of the proposed revised terms and conditions are in recognition of the type of service that is the R1 Service and that the proposed changes provide flexibility for the shipper.

1099. Alinta and Verve Energy both submit that provisions relating to the first and second option periods are based on the original term being 15 years and question why the references to term and capacity end date do not simply refer to a 15 year period.

1100. The concern expressed by Alinta and Verve seems to be a drafting issue and not a matter of substance. The Authority is of the view that revisions proposed by DBP appear reasonable, particularly making the exercise of the option contingent on there being no valid termination for contractual default.

Shipper's gas installations (clause 5)

1101. Clause 5 of the proposed terms and conditions contains the provisions for receiving and delivering gas. The main changes to clause 5 are the inclusion of:

- an obligation on a shipper to pay capacity-related transmission charges in certain events where the operator refuses to deliver gas (clauses 5.6 and 5.9);
- more detailed terms relating to the shipper's obligation to pay for system use gas (clause 5.10);
- additional rights of the operator to refuse to deliver or receive gas in circumstances of emergencies (clause 5.11); and
- obligations on the shipper to have gas installations and appliances inspected in accordance with the *Gas Standards Act 1972 (WA)* (clause 5.12).

1102. DBP submits that the changes to clause 5 of the proposed revised terms and conditions are to address what works in practice or are changes of an administrative/grammatical nature.

Clause 5.2 – Operator must receive and deliver gas

1103. Clause 5.2 of the proposed revised terms and conditions sets out the provisions for when the DBP must deliver and receive gas.

5.2 Operator must Receive and Deliver Gas

~~Subject to this Contract, if Shipper offers Gas for Delivery to Operator at inlet points on the DBNGP, Operator must Receive that Gas from Shipper up to Shipper's Contracted Capacity aggregated across all inlet points on the DBNGP (plus any Capacity under a Spot Transaction) and Operator must deliver Gas to Shipper at nominated outlet points up to its Contracted Capacity aggregated across all outlet points on the DBNGP (plus any Capacity under a Spot Transaction).~~

Subject to any other provision of this Contract, the Operator, on each Gas Day during the Period of Supply:

(a) must Receive at the Nominated Inlet Points the quantity of Gas Delivered by the Shipper under clause 5.1(a); and

(b) must deliver to the Shipper at the Nominated Outlet Points a quantity of Gas up to the Shipper's Contracted Capacity aggregated across all Outlet Points on the DBNGP.

1104. DBP submits that the changes to clause 5.2 of the proposed revised terms and conditions are of an administrative/grammatical nature.

1105. Rio Tinto submits that clause 5.2(b):

- is too vague as it is no use to a shipper if DBP delivers the right amount of gas but at the wrong places; and
- should be amended to say that DBP will deliver gas at the nominated outlet points in the quantities required by the shipper at each point, up to a maximum across all points of the shipper's contracted capacity.

1106. DBP submits that clause 5.2(b) uses the same drafting as is used in the SSC's and therefore no change is required.[505] However, the Authority has considered Rio Tinto's comment on clause 5.2(b) and agrees with Rio Tinto that its suggested amendment is reasonable and improves the certainty and clarity of the provision without materially adversely changing the rights of either the operator or user.

Required Amendment 33

Clause 5.2(b) should be amended to require DBP to deliver gas at the nominated outlet points in the quantities required by the shipper at each point, up to a maximum across all points of the shipper's contracted capacity.

Clause 5.3 – Operator may refuse to receive gas

1107. Clause 5.3(e) provides that the operator may refuse to receive gas in response to a reduction in gas transmission capacity by reason of, or in response to, a reduction in gas transmission capacity caused by the negligence, breach of contractual term or other misconduct of the shipper. This clause has been moved from clause 17.2 (Curtailment Generally) of the existing terms and conditions. DBP submits that the changes to clause 5.3 are for practical reasons.

1108. Alinta and Verve Energy both submit that clause 5.3(e):

- is now a basis on which DBP can refuse to accept to deliver gas rather than a basis on which DBP can curtail the delivery; and
- is outside the 2% allowance of curtailments and that this provision should be deleted from clause 5.3(e) and also 5.6(b) and reinstated in clause 17.2.

1109. In response to third party submissions, DBP submits that the refusal to receive gas in circumstances addressed by clause 5.3(e) were never included in the calculation of the 2% curtailment limit. DBP submits that, nevertheless, it is important to clarify what circumstances give rise to a curtailment and what should be a refusal to deliver/receive. Accordingly, there should be no change to the proposed drafting.

505 DBP, 11 August 2010, Confidential supporting submission # 27: Response to Rio Tinto Submission.

1110. The Authority has considered Alinta and Verve Energy's views outlined above and DBP's response and considers that the proposed amendment to clause 5.3(e), which allows DBP to refuse to receive any gas from a shipper "in response to" a reduction in gas transmission capacity caused by the shipper's misconduct, widens DBP's discretion considerably by removing the requirement for a client link between the misconduct and extent of the reduction in capacity. The Authority also agrees with the submissions made by Alinta and Verve Energy to the effect that it is more appropriate for the issue to be dealt with by way of curtailment than a refusal to receive gas.

1111. Alinta and Verve Energy also submit that clause 5.3(g), relating to DBP's refusal to receive gas in certain circumstances, does not make sense.

1112. Clause 5.3(g) reads:

> [the operator may refuse to receive gas from the shipper at an inlet point] … to the extent that the Receipt of that Gas for a Gas Day at an Inlet Point is in excess of the aggregate of the following in respect of that Inlet Point for that Gas Day all of the Shipper's Contracted Capacity; if the Operator considers as a Reasonable and Prudent Person that to Receive such Gas would interfere with other shippers' rights to their Contracted Firm Capacity.

1113. The words "the following" should be deleted and the words "all of the shipper's contracted capacity" should replace them. DBP agrees that the proposed wording does not make sense and the amendment is required.[506]

Required Amendment 34

- Clause 5.3(e) of the proposed revised terms and conditions should be deleted. Clause 17.2(c) of the existing terms and conditions should be reinstated.
- Clause 5.3(g) of the proposed revised terms and conditions, in relation to being able to refuse to receive gas, should be amended to read "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; if the Operator considers as a Reasonable and Prudent Person that to Receive such Gas would interfere with other shippers' rights to their Contracted Firm Capacity ".

Clause 5.4 – Notification of refusal to receive gas

1114. Clause 5.4 of the proposed revised terms and conditions establishes the terms that DBP must comply with in providing a shipper with a notification of a refusal to receive gas.

[506] DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

1115. The material change to clause 5.4 is the deletion of the words “as soon as practicable” in clause 5.4(c), after the requirement for DBP to notify the shipper of its reasons for refusing to receive gas.

1116. DBP submits that the changes to this clause are for practical reasons. DBP has not provided any further reasoning for the deletion of the words “as soon as practicable” under clause 5.4(c). No interested parties commented on this clause.

1117. The Authority considers that it is reasonable that DBP should notify a shipper of its reasons to refuse to receive gas “as soon as practicable”, and is of the view that the words should be reinstated in clause 5.4(c) of the proposed revised terms and conditions.

Required Amendment 35

Clause 5.4(c) of the proposed revised terms and conditions should be amended to include the words “as soon as practicable’” in relation to DBP providing a shipper with its reasons to refuse to receive gas.

Clause 5.5 – No liability for refusal to receive gas

1118. Clause 5.5 of the proposed revised terms and conditions provides that, subject to clause 23.2 (Liability for fraud), DBP is not liable for any direct or indirect damage caused by or arising out of any refusal to receive gas under clause 5.3 (Operator may refuse to receive gas).

1119. The proposed change to clause 5.5 is the removal of the liability for DBP’s refusal to receive gas being subject to the liability under clause 17 (Curtailment) of the existing terms and conditions. DBP submits that the proposed change to this clause is for reasons of practical experience. No interested parties commented on this clause.

1120. Subject to the required amendments to clause 5.3, the Authority is of the view that the provision for the operator to have no such liability for refusal to receive gas is reasonable.

Refusal to receive gas is a curtailment in limited circumstances; and Refusal to deliver gas is a curtailment in limited circumstances (clauses 5.5 and 5.9 of the 2005 to 2010 terms and conditions respectively)

1121. The proposed revisions delete clauses 5.5 and 5.9 from the existing terms and conditions. These clauses provide that, in certain circumstances where DBP could have taken steps to avoid or minimise the magnitude and duration of a refusal to receive and/or deliver gas, then such refusal constitutes a curtailment for the purposes of the contract. It would then be taken into account in determining whether curtailments aggregated over a gas year cause the permissible curtailment limit to be exceeded.

1122. Alinta and Verve Energy both submit that there is no reason for these protections for the shipper to be removed. They submit that the provisions are important in protecting against the impact of an unreasonable refusal by DBP to receive and/or deliver gas and should be reinstated. Rio Tinto also submits that clause 5.5 and 5.9 of the existing terms and conditions should be reinstated.

1123. In its response to third party submissions, DBP submits that this is not a T1 Service and the differences are explained in DBP's submission #3.[507]

1124. In the context of the Authority's requirement for the access arrangement to include the T1 Service as a reference service, the Authority is of the view that clauses 5.5 and 5.9 of the existing terms and conditions establish reasonable protections for the shipper and these clauses should therefore be retained.

Required Amendment 36

Clause 5 of the proposed revised terms and conditions should be amended to include terms and conditions that are materially the same as clause 5.5 and 5.9 of the existing terms and conditions for the T1 Service, which relates to refusal to receive or deliver gas as a curtailment in limited circumstances.

Clause 5.6 – Operator may refuse to deliver gas

1125. Clause 5.6 of the proposed revised terms and conditions sets out the circumstances under which DBP may refuse to deliver gas to the shipper, including that DBP may refuse to deliver gas as a consequence of refusing to receive out of specification gas, or as a remedy for a breach of an imbalance limit, or DBP may refuse to deliver overrun gas.

1126. The material change to clause 5.6(b) is that it now provides that the operator may refuse to deliver gas in response to a reduction in gas transmission capacity by reason of, or in response to, a reduction in gas transmission capacity caused by the negligence, breach of contractual term or other misconduct of the shipper. This provision has also been moved from clause 17.2 (Curtailment Generally) of the existing terms and conditions.

1127. DBP submits that the proposed changes to clause 5.6 are for practical reasons.

1128. As with clause 5.3(e) of the proposed revised terms and conditions, Alinta and Verve Energy submit that this provision should be deleted from clause 5.6(b) and reinstated in clause 17.2.

1129. The Authority has considered and accepted Alinta and Verve Energy's views and also considers that the proposed new clause 5.6(b), which allows DBP to refuse to deliver gas to a shipper "in response to" a reduction in gas transmission capacity caused by the shipper's misconduct widens DBP's discretion considerably by removing the requirement for a client link between the misconduct and the extent of the refusal to deliver.

507 DBP, 14 April 2010, Confidential supporting submission #3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au

Required Amendment 37

Clause 5.6(b) of the proposed revised terms and conditions, which provides that the operator may refuse to deliver gas in response to a reduction in gas transmission capacity by reason of, or in response to, a reduction in gas transmission capacity caused by the negligence, breach of contractual term or other misconduct of the shipper, should be deleted.

Clause 5.8 – No liability for refusal to deliver gas

1130. Clause 5.8 of the proposed revised terms and conditions provides that, subject to clause 23.2 (Liability for fraud), the Operator is not liable for any direct or indirect damage caused by or arising out of any refusal to deliver gas under clause 5.6 (Operator may refuse to deliver gas).

1131. The material change to clause 5.8 of the proposed revised terms and conditions is that it removes the preservation of liability for DBP's refusal to deliver gas under clause 17 (Curtailment) of the existing terms and conditions.

1132. DBP submits that the proposed changes to clause 5.8 are for practical reasons. No interested parties commented on this clause.

1133. Subject to the required amendments to clause 5.6, the Authority is of the view that the provision for the operator to have no such liability for refusal to deliver gas is reasonable.

Clause 5.9 – No change to contracted capacity

1134. Clause 5.9 which relates to no change to contracted capacity is a new clause.

> **5.9 No change to Contracted Capacity**
>
> (a) A refusal to Deliver Gas under clause 5.6 does not affect the calculation of the Charges payable by the Shipper under clause 20, for which purposes the Shipper's Contracted Capacity remains as specified in the Access Request Form.
>
> (b) When calculating the amount of Total Contracted Capacity (either generally or in respect of a specific Capacity Service, Inlet Point or Outlet Point) for a particular shipper, no reduction is to be made for any capacity not made available as a result of any refusal to Deliver Gas, either generally or in respect of any specific Capacity Service, Inlet Point or Outlet Point, under any of the shippers' contracts for Capacity Service pursuant to that clause which is the material equivalent of clause 5.6.

1135. DBP submits that the introduction of this clause is for practical reasons to provide that a refusal to deliver gas under clause 5.6 of the proposed revised terms and conditions does not affect the calculation of charges payable by the shipper.

1136. Alinta and Verve Energy submit that clause 5.9(a) should be subject to the reinstated clause 5.9 from the existing terms and conditions so that a refusal to deliver gas is a curtailment in certain circumstances. Clause 5.9 from the existing terms and conditions reads:

5.9 Refusal to Deliver Gas is a Curtailment in limited circumstances

To the extent that a refusal to Deliver such Gas under clause 5.7(c) would not have occurred if Operator had taken the steps which would be expected of a Reasonable And Prudent Person to avoid the need for, or failing such avoidance, to minimise the magnitude and duration of, the refusal to Deliver Gas, a refusal to Deliver Gas under clause 5.7(c):

(a) is a Curtailment for the purposes of this Contract; and

(b) shall be taken into account in determining whether Curtailments aggregated over a Gas Year cause the T1 Permissible Curtailment Limit to be exceeded.

1137. Alinta and Verve Energy also submit that clause 5.9(a) of the proposed revised terms and conditions should be amended to reflect situations where the capacity reservation charge must be refunded under clause 17.4 for a refusal to deliver gas.

1138. In response to third party submissions, DBP submits that this is not a T1 Service and the differences are explained in DBP's submission #3.[508]

1139. The Authority is of the view that the provisions of the proposed clause 5.9 in relation to no change to contracted consistent with Alinta's and Verve Energy's submissions, capacity should be subject to the refusal to deliver gas being a curtailment in certain circumstances as contemplated by clause 5.9 of the existing terms and conditions, and should be amended to reflect situations where the capacity reservation charge must be refunded under clause 17.4 for a refusal to deliver gas.

Required Amendment 38

Clause 5.9 of the proposed revised terms and conditions, in relation to no change in contracted capacity, should be amended to:

- include provisions that are materially the same as those in clause 5.9 of the existing terms and conditions where the refusal to deliver gas is a curtailment in certain circumstances; and
- be amended to reflect situations where the capacity reservation charge must be refunded under clause 17.4 for a refusal to deliver gas.

508 DBP, 14 April 2010, Confidential supporting submission #3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au

Clause 5.10 – System use gas

1140. Clause 5.10 of the proposed revised terms and conditions sets out the conditions under which DBP must supply the shipper's share of system use gas. Clause 5.10 of the proposed revised terms and conditions includes greater detail relating to the shipper's obligation to pay for system use gas. DBP submits that the revisions included in clause 5.10 of the proposed revised terms and conditions are for practical reasons.

1141. The material new provision included in clause 5.10 is that it provides an indemnity by the shipper in favour of the operator in respect of the cost of additional gas incurred by the operator in supplying system use gas in circumstances where the shipper's conduct has resulted in the requirement for additional gas, to the extent that the costs are not recovered by the operator by other charges. An independent verification process is established to confirm the relevant costs.

1142. The proposed new provisions in clause 5.10 are as follows.

5.10 System Use Gas

(a) The Operator must supply the Shipper's share of System Use Gas.

<u>(b) For the purposes of this clause 5.10, the Shipper's share of System Use Gas for a Gas Day is calculated by:</u>

<u>(i) multiplying the total amount of all System Use Gas used on that Gas Day by the total quantity of Gas delivered on that Gas Day to the Shipper (under the R1 Service) downstream of CS7; and</u>

<u>(ii) dividing the result by the quantity of Gas delivered on that Gas Day to all shippers across all Capacity Services and Spot Capacity, downstream of CS7.</u>

<u>(c) The Shipper must indemnify the Operator in respect of the cost of additional Gas incurred by the Operator in supplying System Use Gas for the Dampier To Bunbury Natural Gas Pipeline in accordance with this Contract to the extent to which that System Use Gas is required to be supplied, in accordance with Good Gas Industry Practice, because of the Shipper taking Overrun Gas or breaching the Accumulated Imbalance Limit or the Hourly Peaking Limit on any Gas Day, aggregated over a Contract Year, but only if that cost is not recovered by the Operator during that Contract Year by Other Charges or Direct Damages paid by the Shipper.</u>

<u>(d) The Operator must provide, each quarter, an indicative report (Quarterly Report) (for the Shipper's information only) of the costs incurred by the Operator in supplying System Use Gas in the circumstances described in clause 5.10(c). The costs notified in the Quarterly Report are not final and are subject to the reconciliation at the end of each Contract Year of actual costs incurred and of any recovery of those costs by the Operator during the Contract Year by way of Other Charges or Direct Damages paid by the Shipper.</u>

<u>(e) Within 30 days after receipt of a Tax Invoice which includes an amount payable by the Shipper under clause 5.10(c), the Shipper may request an independent verification of the amount payable.</u>

<u>(f) If requested under clause 5.10(e), the independent verification must be undertaken by an auditor independent of the parties and agreed to by them or, failing agreement, by an auditor appointed as if he or she were to be an Expert for a Technical Matter under clause 24.</u>

(g) The Operator must disclose all relevant information in relation to the calculation of the amount payable under clause 5.10(c) to the auditor agreed or appointed under clause 5.10(f). The auditor must not disclose that information to the Shipper, but must review the information provided by the Operator and such further information as the auditor may reasonably request from the Operator, and must then determine whether the amount included in the Operator's Tax Invoice is correct or, if not, the correct amount to be included.

(h) A determination of an auditor under clause 5.10(g) is final and binding upon the Parties.

1143. Rio Tinto supports the introduction of greater clarity and has no in principle objection to the new provisions in clause 5.10, noting three points of detail:

- clauses 5.10(a) and (b) seem to leave a gap in respect of any system use gas used to transport gas to points upstream of CS7;
- clause 5.10(a) should make it express that the cost of that provision is included in the tariff, and is not to be the subject of an additional charge; and
- clause 5.10(a) needs to be broader, and oblige DBP to provide all system use gas, not just the shipper's share.

1144. BHP Billiton submits that clause 5.10 should be amended to entitle, but not oblige, shippers to supply their own system use gas. BHP Billiton submits that:

- allowing shippers to supply their own system use gas is the most efficient option, as the party who is in the best position to supply the system use gas will ultimately end up doing so; and
- DBP's proposal that the operator supply the shipper's share of system use gas should be rejected on the basis that it does not promote efficiency and is inconsistent with the national gas objective and rule 100 of the NGR.

1145. In its response to third party submissions, DBP submits that, in line with the nature of the R1 Service, the requirement that the operator supply the shipper's system use gas simplifies the operation of the service. However, DBP submits that if a shipper is to be given the right to supply its own share of system use gas, then it must be for a minimum term equal to the term of the reference service contract or for a term that operates "back to back" with the term of DBP's own system use gas supply arrangements.

1146. Alinta and Verve Energy both submit in relation to clause 5.10 that:

- the auditor should be nominated by the shipper (and agreed by the operator) and the auditor should be required to hand down his or her decision within 30 days after having received all relevant information from the operator in accordance with clause 5.10(g); and
- a new provision should be inserted clarifying that the verification process in clause 5.10 is not a dispute over a tax invoice for the purposes of clause 21.5, and that no interest is payable by the shipper in any circumstances for the period prior to the handing down of the auditor's decision.

1147. In response to these submissions, DBP submits that there is no detriment to the shipper of the auditor being an independent third party agreed between the parties (with a mechanism for appointment if there is no agreement).

1148. Alinta and Verve Energy also both submit that:

- the concept of "share of system use gas" defined in clause 5.10(c) has no role in clause 5.10, as there is no basis upon which DBP is to determine whether system use gas is required to be supplied because of the shipper's identified conduct, other shippers' conduct or other operating conditions;
- any attempt to allocate additional costs of system use gas to isolated episodes of one shipper's conduct will be artificial, arbitrary and unsupportable;
- clause 5.10(c) allows the operator to include in a tax invoice the amount it considers it should be indemnified, and will be a source of constant dispute based on doubts as to the cause of the need for system use gas; and
- the additional indemnity over and above the obligation to pay relevant "Other Charges" and Direct Damages is contentious, unnecessary and unreasonable and should be deleted.

1149. In its response to these submissions DBP submits that the concept of "share of system use gas" does have a role in clause 5.10 because it is the basis upon which the indemnity is to be calculated. With no obligation on the shipper to nominate, DBP cannot meaningfully plan for its system use gas requirements (coupled with the extensive overrun and peaking rights under the SSCs).

1150. Taking into account the matters in the submissions, the Authority considers these are three issues mainly in relation to the proposed clause 5.10:

- the purpose and operation of proposed clauses 5.10(a) and 5.10(b), indicating a method of determination of a shipper's "share" of system use gas;
- the provisions of clause 5.10(c) to (h) that have the effect that a shipper may potentially be required to pay for costs of additional system use gas that is required because of the shipper taking overrun gas or breaching the accumulated imbalance limit or the hourly peaking limit; and
- whether users should be able to supply system use gas rather than only the operator providing system use gas.

1151. Clauses 5.10(a) and 5.10(b) require the operator to supply a shipper's share of system use gas, where that share is determined as the total amount of system user gas multiplied by the proportion of gas deliveries downstream of CS7 that is for the shipper.

1152. The purpose of clauses 5.10(a) is that DBP will provide system use gas. This is consistent with the determination of reference tariffs, for which the cost of system use gas is an element of forecast operating expenditure that is recovered through the commodity tariff. However, the purpose of clause 5.10(b) and the determination of a user's "share of system use gas" is not obvious as the value of a shipper's share of system use gas is not applied in determining the operator's or shipper's obligations and liabilities under an access contract.

1153. The proposed clauses 5.10(c) to (h) provide for DBP to recover from a user the cost of any additional system use gas that is made necessary by a user taking overrun gas or breaching the accumulated imbalance limit or the hourly peaking limit. The rationale for this provision is that a user should bear the cost of any additional system use gas that is necessary as a result of the user failing to comply with requirements in the use of the service. However, consistent with the submissions of Alinta and Verve Energy, the Authority considers that there would be practical difficulties in establishing a clear causal connection between an action of the user and the extent to which that action increased the amounts of system use gas required on any particular day. As a consequence, the Authority considers that there is a high probability that the provisions of clauses 5.10(c) to (h) would be inoperable and as such there is a high risk of disputes between the shipper and operator.

1154. Taking the above matters into account, the Authority is of the view that clause 5.10 of the proposed revised terms and conditions is inconsistent with the national gas objective because it creates unjustified complexity in the operation of the terms and conditions and is not likely to work in practice.

1155. The Authority considers that there is no in-principle reason why shippers should not be permitted to provide system use gas. The Authority observes that other gas transmission lines, including the Goldfields Gas Pipeline, operate on the basis of shippers providing system use gas.

1156. The Authority accepts, however, DBP's contention that it is operationally simpler for the operator to provide system use gas. Moreover, making provision for shippers to provide system use gas would require changes to the terms of the access arrangement and reference services including:

- a change in the calculation of a shipper's share of system use gas to take into account both the quantity and distance of gas delivery for the shipper;
- a mechanism to provide a discount to the commodity tariff where a shipper opts to provide system use gas.

1157. Only one shipper (BHP Billiton) has made a submission requesting that the terms and conditions make provision for a shipper to supply system user gas, arguing that this is likely to result in the most efficient sourcing of system use gas. The Authority does not accept that this is necessarily the case. Under the current arrangement where the reference tariff makes provision only for DBP to recover a forecast cost of system user gas, DBP has a strong commercial incentive to minimise the cost of purchases of system use gas.

1158. The Authority considers that there is insufficient demonstration of demand by shippers to supply system use gas, and insufficient evidence that current arrangements are resulting in inefficient outcomes, for the Authority to determine that the current requirement that the operator provides all system use gas is inconsistent with the National Gas Objective. Therefore the Authority will not require amendment of the terms and conditions to allow users to opt to supply system use gas.

Required Amendment 39

Clause 5.10 of the proposed revised terms and conditions, in relation to system use gas, should be amended to:

- delete the proposed sub-clauses 5.10(a) and (b) and replace these with a clause to the effect that the operator will provide such system use gas as is reasonably necessary to provide the service; and
- delete the proposed clauses 5.10(c) to (h).

Clause 5.11 – Additional rights to refuse to receive or deliver gas

1159. Clause 5.11 of the proposed revised terms and conditions provides for additional rights to be available to DBP under any Law or under the contract to refuse to receive or deliver gas in certain circumstances or emergencies.

1160. The main change to clause 5.11 is that under clause 5.11(ii) this may now include, where the Minister, or any other person, regulatory authority or body, declares a state of emergency under the *Emergency Management Act 2005 (WA)*.

1161. Consistent with the existing terms and conditions, clause 5.11 also provides that this may include where the Governor or any other person, regulatory authority or body declares a state of emergency under the *Fuel, Energy and Power Resources Act 1972 (WA),* or where the Coordinator of Energy or any other person, regulatory authority or body declares a state of emergency under the *Energy Coordination Act 1994 (WA).*

1162. Rio Tinto was the only interested party that commented on the inclusion of additional rights for DBP to refuse to receive or deliver gas if a state of emergency is declared under the *Emergency Management Act 2005 (WA)* and submitted that it does not object to clause 5.11(ii).[509]

1163. The Authority is of the view that the inclusion of clause 5.11(ii) is reasonable. Accordingly, the Authority approves of the proposed changes to clause 5.11.

Clause 5.12 – Shipper's gas installations

1164. Clause 5.12 of the proposed revised terms and conditions is a new clause requiring a shipper, at its cost, to have gas installations and appliances inspected in accordance with the *Gas Standards Act 1972 (WA).* This proposed clause is mandatory.

[509] Rio Tinto submission, 20 July 2010.

1165. The Authority is of the view that the inclusion of this clause is unlikely to promote the efficient investment in, and the efficient operation and use of, natural gas services for the long term interests of consumers as it is likely to add additional costs to shippers where it is unnecessary for such costs to be incurred. The Authority considers that the requirement be amended from being mandatory to being at the request of DBP acting reasonably.

Required Amendment 40

Clause 5.12 of the proposed revised terms and conditions, in relation to shipper's gas installations, should be amended from it being mandatory for a shipper, at its cost, to inspect its facilities to ensure it complies with applicable legislation to it being at the request of DBP acting reasonably.

Inlet and outlet points (clause 6)

1166. Clause 6 of the proposed terms and conditions relates to inlet and outlet points and establishes the terms for such things as multi-shipper agreements, multi-shipper inlet points and multi-shipper outlet points, the allocation of gas at inlet and outlet points, and the design and installation of inlet and outlet stations.

1167. The changes to clause 6 of the proposed revised terms and conditions include more detailed terms relating to:

- the operation of multi-shipper agreements at inlet and outlet points (clauses 6.4 and 6.5);
- the design and installation of inlet stations, inlet point connection facilities, and outlet stations (clauses 6.6, 6.7, and 6.8);
- the treatment of notional gate points for delivery of gas to sub-networks, and the design and installation of gate stations (clause 6.10 and 6.11); and
- maintenance charges for inlet stations, outlet stations and gate stations (clause 6.12).

1168. DBP submits that the changes to clause 6 of the proposed revised terms and conditions are to address what works in practice, or are changes of an administrative/grammatical nature.

Clause 6.1 – Inlet points and outlet points

1169. Clause 6.1(a) of the proposed revised terms and conditions provides that the inlet and outlet points for the contract are set out in the Access Request Form. The changes to this clause are minor and DBP submits that they are of an administrative/grammatical nature.

1170. Alinta and Verve Energy both submit that the Access Request Form, as referred to in clause 6 of the proposed revised terms and conditions, is not defined in any way which connects it to the request resulting in the contract and that this connection must be established.

1171. In its response to third party submissions, DBP advises that the terms and conditions will be appended to the Access Request Form which, when executed, will constitute the contract between the parties.

1172. The Authority is of the view that in light of the amended definition of "Access Request Form" referred to at paragraph 1086 DBP's response to Alinta and Verve Energy's concerns in relation to the Access Request Form is satisfactory. The Authority approves the proposed changes to clause 6.1.

Clause 6.4 – Allocation of gas at inlet points

1173. Clause 6.4 of the proposed revised terms and conditions provides that gas delivered by the shipper to an inlet point is deemed to be received by DBP in the order specified generally or for a particular gas day by the shipper. If the shipper fails to specify the order for any gas day, then, firstly, gas is deemed to be received for any available R1 Service. DBP submits that the changes to this clause are for practical reasons.

1174. The proposed changes to clause 6.4 are to provide more detailed terms relating to the operation of multi shipper agreements at inlet and outlet points. Rio Tinto submits that it supports the clarification of these provisions and also of those in clause 6.5, relating to allocation of gas at outlet points.

1175. Alinta and Verve Energy both submit that this provision provides that the R1 Service will, in the absence of a shipper specification, be treated as a priority to the T1 Service, which is not acceptable as a shipper may have contracts for T1 and R1 Services.

1176. In its response to third party submissions, DBP advises that this is a typographical error and it will be made clear that the order will be the same order as per the curtailment plan.

1177. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority requires that clause 6.4 of the proposed revised terms and conditions be amended to include provisions that are materially the same as those in clause 6.4 of the existing terms and conditions.

Required Amendment 41

Clause 6.4 of the proposed revised terms and conditions in relation to allocation of gas at inlet points should be amended to include provisions that are substantially the same as those in clause 6.4(c) and (d) of the existing terms and conditions.

Clause 6.6 – Design and installation of inlet stations

1178. Clause 6.6 of the proposed revised terms and conditions provide a requirement that the shipper design and install, or procure the design and installation, of the parts of an inlet station that are upstream of the inlet point, and the same requirement applies jointly to shippers that collectively deliver gas to an inlet point. The provisions of this clause do not differ materially from clause 6.6(a)(1) and 6.6(b)(i) of the existing terms and conditions.

1179. Rio Tinto submits that:

- since the assets of the inlet points form part of the DBNGP, the Authority must ensure that there are suitable safeguards against DBP double-recovering any money by the shipper financing the relevant parts of inlet points and also through the regulated tariff; and
- the clause should impose a prudence test in accordance with NGR 79(1)(a), if not a justifiability test in accordance with NGR 79(1) (b).

1180. The concerns of Rio Tinto are addressed by the provisions of rules 79 and 82 of the NGR that limit the ability of DBP to add capital expenditure to the capital base to expenditure that meets the tests of rule 79, and prevents DBP from benefiting from capital expenditure that is financed by users through capital contributions.

Clause 6.7 – Design and installation of inlet point connection facilities

1181. Clause 6.7 of the proposed revised terms and conditions includes increased detail in relation to the design and installation of inlet point connection facilities.

1182. DBP submits that the changes to clause 6.7 are either for practical reasons or are of an administrative/grammatical nature.

1183. Alinta and Verve Energy note that clause 6.7(d) refers to a right of access for the purpose of maintaining and operating an outlet station, and that this should be a reference to an inlet station. DBP agrees that this should be changed.

1184. Rio Tinto submits that clause 6.7 should be amended to :

- impose a prudence test in accordance with NGR 79(1)(a), if not a justifiability test in accordance with NGR 79(1) (b);
- include express reference to the grandfathering in clause 6.13; and
- include express references for dispute resolution.

1185. The Authority has considered the above matters and is of the view that a prudence or justifiability test is not appropriate for the same reasons. The Authority agrees with Rio Tinto that clause 6.7 should be made expressly subject to clause 6.13 so that it is clear that the additional charges referred to will not apply to existing stations.

Required Amendment 42

Clause 6.7 should be amended by inserting the words “Subject to clause 6.13” at the commencement of the second sentence in clause 6.7(a).

Clause 6.7(d) should be amended to refer to an outlet, not inlet, station.

Clause 6.8 – Design and installation of outlet stations

1186. Clause 6.8 of the proposed revised terms and conditions includes more detailed terms relating to the design and installation of outlet stations. It provides that DBP must, at the shipper's request, design and install or procure the design and installation of any required outlet station that is not a gate station.

1187. DBP submits that the proposed changes to clause 6.8 are either for practical reasons and are of an administrative/grammatical nature.

1188. Rio Tinto submits that clause 6.8 should be amended to:

- impose a prudence test in accordance with NGR 79(1)(a), if not a justifiability test in accordance with NGR 79(1) (b);
- include express reference to the grandfathering in clause 6.13; and
- include express references to dispute resolution.

1189. The Authority has considered the above matters and is of the view that, given the outlet station is being installed at the request of the shipper, a prudence or justifiability test is not appropriate. However, the Authority is of the view that it is reasonable and appropriate to limit the operator's ability to charge an unreasonable amount for such work. The Authority agrees with Rio Tinto that clause 6.8 should be made expressly subject to clause 6.13 so that it is clear that the additional charges referred to will not apply to existing stations.

Required Amendment 43

Clause 6.8(a) should be amended by:

- inserting the words "Subject to clause 6.13" at the commencement of the second sentence; and
- 6.8(a)(i) reading 'to pay the costs reasonably incurred by the Operator in accordance with good industry practice…"

Clause 6.10 – Notional gate point

1190. Clause 6.10 of the proposed revised terms and conditions contains more detailed terms in relation to notional gate points. It provides for a notional gate point for each sub-network, at which all outlet point contracted capacity, in respect of that sub-network, is taken to be located.

1191. DBP submits that the proposed changes to clause 6.10 are for practical reasons and are of an administrative/grammatical nature.

1192. Rio Tinto submits that clause 6.10 should be amended to:

- impose a prudence test in accordance with NGR 79(1)(a), if not a justifiability test in accordance with NGR 79(1) (b);
- include express reference to the grandfathering in clause 6; and
- include express references to dispute resolution.

1193. The Authority is of the view that it is appropriate for the DBP to be required to manage the delivery of gas from the notional gate point to the associated sub-network reasonably and in accordance with good industry practice. The Authority is of the view there is no need to expressly refer to clause 6.13 or the dispute resolution provisions in the agreement.

Required Amendment 44

Clause 6.10(c) about notional gate point should be amended to replace "absolute" with "reasonable" and to insert "in accordance with good industry practice" after "discretion".

Clause 6.12 – Maintenance charge for inlet stations, outlet stations and gate Stations

1194. Clause 6.12 proposes more detailed terms relating to maintenance charges for inlet stations, outlet stations, and gate stations associated with a sub network. Clause 6.12 provides that the maintenance charge is determined by DBP acting as a reasonable and prudent person as being sufficient to allow DBP to amortise, over the life of the inlet station, outlet station or gate station, so much of the relevant construction costs as are not already paid by any shipper under clauses 6.6 (Design and installation of inlet stations) or 6.8 (Design and installation of outlet stations) of the terms and conditions.

1195. DBP submits that the proposed changes to clause 6.12 of the proposed revised terms and conditions, relating to operating specifications, are to address what works in practice or are changes of an administrative/grammatical nature. Changes include:

- the shipper is liable to pay a charge for maintaining, operating, refurbishing, upgrading, replacing and decommissioning a relevant station, whereas under the existing terms and conditions the shipper is only liable to pay a charge for maintaining, operating and decommissioning a relevant station; and
- the provision allowing a shipper to request a breakdown of the maintenance charge has been deleted.

1196. Rio Tinto submits that clause 6.12 (as with 6.6, 6.7 and 6.9 and 6.10) should:

- impose a prudence test in accordance with NGR 79(1)(a), if not a justifiability test in accordance with NGR 79(1) (b);
- include express reference to the grandfathering in clause 6.13; and
- include express references to dispute resolution.

1197. The Authority is not satisfied that the amendments are appropriate in the absence of any mechanism to enable a shipper to ensure that only necessary refurbishments and upgrades are carried out. The Authority is also concerned that deletion of the provision allowing a shipper to obtain a breakdown of the maintenance charge may not promote the efficient investment in, and the efficient operation and use of, natural gas services for the long term interests of consumers as such costs would no longer be transparent or able to be verified.

1198. Verve Energy and Alinta submit that the words in clause 6.12 "…across all shippers who pay a charge for substantially the same purpose" should be replaced with "…across all shippers who use the inlet station, outlet station or gate station associated with a sub-network…" DBP in its response to third party submissions advises that it does not accept that the suggested amendment is required to improve interpretation in this clause.

1199. The Authority has considered the above matters and is of the view that the amendment suggested by Verve Energy and Alinta is more precise and is necessary to provide a clearer understanding of the meaning and effect of the clause.

Required Amendment 45

Clause 6.12(a) should be amended to:

- include a mechanism to enable a shipper to ensure that only necessary refurbishments and upgrades are carried out;
- include a provision allowing a shipper to obtain a breakdown of the maintenance charge; and
- replace the words "pay a charge for substantially the same purpose" with "use the inlet station, outlet station or gate station associated with a sub-network" and by deleting sub-clauses (iii) and (iv).

Operating Specifications (clause 7)

Clause 7.2 – Gas to be free from certain substances

1200. Clause 7.2 of the proposed revised terms and conditions provides that gas delivered at an inlet or an outlet point must be free, by normal commercial standards from dust and certain other constituents. The proposed change to the clause is that this is to be "as determined by the operator". DBP submits that the proposed change to this clause is for practical reasons.

1201. Rio Tinto submits that DBP has sought to modify the industry standard test, which is based on AS 4564, by adding a subjective element with the words "as determined by the operator". Rio Tinto submits that the test should be left objective. Alinta and Verve Energy also both submit that the test should be an objective one, and the reference to "as determined by the operator" should be deleted.

1202. In response to third party submissions, DBP submits that the operator has ultimate responsibility for the safety and integrity of the DBNGP and is therefore in the best position to determine what "normal commercial standards" are as that term relates to the DBNGP.

1203. The Authority is of the view that the inclusion of this clause may not promote the efficient investment in, and the efficient operation and use of, natural gas services for the long term interests of consumers as there is no obligation on DBP to make such a determination acting reasonably. The Authority considers that the requirement be amended to require DBP to act reasonably in making its determination.

Required Amendment 46

Clause 7.2 of the proposed revised terms and conditions, in relation to the requirement for gas to be free from certain substances, should be amended to include the word “reasonably” between the words “as” and “determined by the operator”.

Clause 7.4 – Gas temperature and pressure

1204. Clause 7.4 of the proposed revised terms and conditions sets out the provisions for gas temperature and pressure. The main change to clause 7.4 of the proposed revised terms is the inclusion of more detailed terms and conditions in relation to gas temperature and pressure.

1205. Clause 7.4 provides that the minimum and maximum temperatures and the minimum and maximum pressures at which the shipper may deliver gas to DBP at the inlet points, and that DBP may Deliver Gas to the shipper at the outlet points, are those set out in the Access Request Form, Item 2 of Schedule 3.

1206. DBP submits that the proposed changes to clause 7.4 are either for practical reasons or are administrative/grammatical changes.

1207. Alinta and Verve Energy submit that there is a typographical error in clause 7.4(c) that should be amended. DBP agrees in its response to third party submissions.

Required Amendment 47

Clause 7.4(c) of the proposed revised terms and conditions, in relation to gas temperature and pressure, should amend the words “receive gas” to “receives gas”.

Clause 7.9 – Shipper may receive out of specification gas

1208. Clause 7.9 of the proposed revised terms and conditions provides for the shipper to receive out-of-specification gas. Clause 7.9(b) provides the following:

- If any Out-of-Specification Gas is delivered to the Shipper at an Outlet Point without the Shipper's agreement under clause 7.9(a), then except to the extent that the Shipper caused the Gas in the DBNGP to be Out-of-Specification Gas the Operator is liable to the Shipper for Direct Damage arising in respect of the Out-of-Specification Gas.

1209. The changes to clause 7.9 are of a minor grammatical nature.

1210. Alinta and Verve Energy submit that the words “by delivering out-of-specification gas to the inlet point” should be added after the words “to be out-of-specification gas”. DBP in its response to third party submissions agrees that this additional wording could assist with interpretation.

Required Amendment 48

Clause 7.9(b) of the proposed revised terms and conditions, in relation to the shipper being able to receive out-of-specification gas, should be amended to add the words “by delivering out-of-specification gas to the inlet point” after the words “to be out-of-specification gas”.

Clause 7.12 – Odorisation

1211. Clause 7.12 of the proposed revised terms and conditions provides that DBP will deliver gas to the shipper at each outlet point at which odorising occurred as at 27 October 2004.

1212. The change to clause 7.12 of the proposed revised terms and conditions is that it now provides that DBP will deliver gas to the shipper at each outlet point at which odorising occurred as at 27 October 2004, rather than the point at which odorising occurred as at the beginning of the access arrangement period.

1213. Alinta and Verve Energy both submit that the operator should also be required to deliver odorised gas at outlet points as agreed in writing with the shipper.

1214. In its response to third party submissions (submission #26), DBP submits that the operator has not previously been required to deliver odorised gas at outlet points as agreed with the shipper. Further, if the parties agree to such a delivery then there is no need to include such a "requirement" in the terms and conditions.

1215. The Authority is of the view that as it is open to DBP and a user to agree for DBP to odorise gas, and such an agreement will include the charges to be paid to DBP for this service, the terms and conditions of the reference service need not anticipate any such agreement.

Clause 7.13 – Weighted average gas flow

1216. Clause 7.13 of the proposed revised terms and conditions provides that if on a gas day, the individual gas delivered by the shipper to an inlet point, that is a multi-shipper inlet point, is included in blended gas that meets the blended specifications, then DBP must receive the individual gas from the shipper even if the individual gas is out-of- specification gas.

1217. The provisions of clause 7.13 are largely the same as the existing terms and condition except that the clause now includes a definition of individual gas which means gas delivered into a blended gas stream immediately prior to it becoming blended gas.

1218. DBP submits that the changes to clause 7.13 of the proposed terms and conditions in relation to weighted average gas flow are for practical reasons. No interested parties commented on this clause.

1219. The Authority accepts the proposed changes to clause 7.13 of the proposed revised terms and conditions.

Nominations (clause 8)

1220. Clause 8 of the proposed revised terms and conditions, in relation to nominations, provides that, to the extent that the contract prescribes certain things to be done by the shipper relating to gas being received by DBP at an inlet point, the shipper may by agreement with a producer or an appointed agent, appoint the producer or the appointed agent to do those things. However, nothing in any such agreement relieves the shipper of its obligations to DBP under the contract.

1221. Proposed changes to clause 8 include:

- the insertion of more detailed terms dealing with allocation/scheduling of daily nominations (clauses 8.9 and 8.10);
- the removal of terms relating to nominations for aggregated services (2005 to 2010 terms and conditions, clauses 8.15 and 8.16); and
- the removal of terms relating to the use of a full haul service for delivery of gas at an outlet point upstream of compressor station 9 (2005 to 2010 terms and conditions, clause 8.18).

1222. DBP submits that the changes to clause 8 in relation to nominations are either to address what works in practice or are changes of an administrative/grammatical nature.

Clause 8.5 – Operator to make available bulletins of available capacity

1223. Clause 8.5 of the proposed terms and conditions provides that the operator must, on regular occasions during each gas day make available on the CRS a bulletin specifying for at least that gas day and the following gas day, the amount of capacity available or anticipated to be available for nomination or renomination.

1224. DBP has proposed minor changes to clause 8.5 of the proposed terms and conditions, relating to the operator making available bulletins of available capacity. DBP submits that the changes are for practical reasons. No interested parties commented on this clause. The Authority accepts the proposed changes to clause 8.5.

Clause 8.6 – Shipper’s initial nomination

1225. Clause 8.6 of the proposed revised terms and conditions sets out the terms for a shipper’s initial nomination. The main change to clause 8.6 is that it is mandatory, rather than optional, for the shipper to give notice to DBP, no later than 14:00 hours on any gas day, of the nomination for the following gas day of the quantity of gas that the shipper requires to deliver to DBP at each nominated inlet point, and the quantity of gas that the shipper requires to receive from DBP at each nominated outlet point.

1226. DBP submits that the changes to clause 8.6 of the proposed revised terms and conditions, relating to the shipper’s initial nomination, are for practical reasons.

1227. No interested parties commented on this clause. The Authority accepts that the proposed changes to clause 8.6 of the proposed revised terms and conditions are reasonable.

Clause 8.8 – Nominations priority

1228. Clause 8.8 of the proposed revised terms and conditions sets out the priority of scheduling capacity services in respect of nominations.

1229. DBP has proposed minor changes to clause 8.8 of the proposed terms and conditions, relating to nominations priority, for practical reasons.

1230. No interested parties commented on this clause. The Authority accepts the proposed changes to clause 8.8.

Clause 8.9 – Scheduling of daily nominations

1231. Clause 8.9 of the proposed revised terms and conditions is a new clause about the scheduling of daily nominations. DBP submits that the inclusion of this clause is for practical reasons.

1232. Clause 8.9 provides that DBP must, by no later than 16:00 hours on each gas day, by notice to the shipper, schedule capacity services in respect of the shipper's initial nomination for the nominated day and, if applicable under the rules governing the market for spot capacity, schedule capacity services for each nominated inlet point and for each nominated outlet point.

1233. Alinta and Verve Energy submit that, as the only capacity service being scheduled under clause 8.9 is the R1 Service, references in this clause to capacity services are confusing, redundant and should be deleted.

1234. In its response to third party submissions, DBP submits that this clause needs to remain because there is a need for consistent drafting across all services in this regard.

1235. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that clause 8.9 of the proposed revised terms and conditions should be amended to replace references to the R1 Service with references to a T1 Service.

Required Amendment 49

Clause 8.9 of the proposed revised terms and conditions, in relation to the scheduling of daily nominations, should be amended to replace references to a R1 Service with references to a T1 Service.

Clause 8.10 – Scheduling where there is insufficient available capacity

1236. Clause 8.10 of the proposed revised terms and conditions is a new clause that provides that DBP may schedule a capacity service for the R1 Service to the shipper which is less than the shipper's initial nomination for the R1 Service at an inlet point or an outlet point. DBP submits that the inclusion of this clause is for practical reasons.

1237. Alinta and Verve Energy submit that a new clause 8.10(c) should be inserted, where DBP must endeavour as a reasonable and prudent person to ensure that where the scheduled capacity services in respect of daily nominations is less than the initial nomination (calculated across all of the shipper's R1 contracts) the difference is kept to the smallest amount possible.

1238. In its response to third party submissions, DBP advises that:

- it does not agree that such a clause is appropriate from an operational perspective;
- in the absence of an appropriate and workable methodology for measuring what is "the smallest amount possible" for any given shipper, such a clause would likely lead to disputes between the parties; and
- the clause provides an appropriate curtailment and nomination process based on "operationally feasibility".

1239. The Authority has considered the views outlined above and agrees with DBP that, in the absence of an appropriate and workable methodology for measuring what is "the smallest amount possible" for any given shipper, the clause proposed by Alinta and Verve Energy would likely lead to disputes between the parties. However, the Authority is of the view that it is reasonable to require DBP to use its best endeavours to minimise the extent of any curtailment required under clause 8.10(b).

Required Amendment 50

Clause 8.10 of the proposed revised terms and conditions, in relation to scheduling where there is insufficient available capacity, should be amended by inserting a new clause 8.10(c) to read "the operator shall use its best endeavours to minimise the extent of any curtailment required under clause 8.10(b)".

Clause 8.15 and 8.16 - Aggregated T1 Service and Nominations at inlet points and outlet points where Shipper does not have sufficient Contracted Capacity (clauses 8.15 and 8.16 in the 2005 to 2010 terms and conditions respectively)

1240. The proposed revised terms and conditions remove the provisions relating to aggregation, which allow a shipper to make short term relocations of capacity by nominating at a point where it does not have contracted capacity, or by nominating in excess of its contracted capacity at a point, provided it makes an equivalent reduction in its nominations elsewhere so that it does not in aggregate exceed its total contracted capacity.

1241. DBP submits that the proposed removal of clauses 8.15 and 8.16 of the proposed revised terms and conditions is due to the clauses not being suitable for an R1 service. DBP submits that the proposed removal of clause 8.15 in relation to aggregation is due to the pipeline's design assumptions being such that if these additional rights are afforded to shippers, it sterilises so much capacity that it is an inefficient allocation of resources (DBP's submission #5). DBP submits that the proposed removal of clause 8.16 in relation to nominations at inlet points and outlet points where a shipper does not have sufficient contracted capacity is due to the pipeline's design assumptions being such that if these additional rights are afforded to shippers, it sterilises so much capacity that it is an inefficient allocation of resources.[510]

1242. Rio Tinto submits that the relocation rights in clauses 8.15 and 8.16 are a very important risk-mitigation right for shippers, to allow them to mitigate:

- the take-or-pay risk under their gas supply agreements;
- the curtailment risk under their gas supply agreements;
- the risk of operational fluctuations; and
- various other risks in the fuel or electricity supply chain.

1243. Rio Tinto submits that a service without short-term relocation rights is much more rigid, materially less valuable and will operate far less efficiently than a service with those rights. Rio Tinto submits that the removal of these rights is unjustified and is not consistent with the national gas objective, and requests their reinstatement.

1244. Verve Energy and Alinta both submit that, in the absence of provisions which govern the nomination, scheduling and curtailment of the R1 Service at outlet points at which the shipper does not have contracted capacity, or nominates in excess of its contracted capacity, it is unclear how the contract operates.

1245. In its response to third party submissions, DBP submits that this is not a T1 Service and does not provide all the rights of a T1 service and the differences are explained in DBP's submission #3.

1246. The Authority has considered the submissions relating to aggregation and agrees with Rio Tinto that the relocation rights are an important risk-mitigation for shippers. The Authority is also of the view that DBP has not provided sufficient justification for removing these provisions from the terms and conditions.

1247. However, the Authority is of the view that given its decision that the service should be a T1 service, clause 8 of the proposed revised terms and conditions should be amended to include provisions that are materially the same as those in clauses 8.15 and 8.16 of the 2005 to 2010 terms and conditions in relation to an aggregated T1 service and nominations at inlet points and outlet points where a shipper does not have sufficient contracted capacity.

510 DBP, 14 April 2010, Confidential supporting submission # 5: Terms and Conditions Comparison. A public version of this submission is available at: www.erawa.com.au

Required Amendment 51

Clause 8 of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clauses 8.15 and 8.16 in the existing terms and conditions in relation to an aggregated T1 service; and nominations at inlet points and outlet points where a shipper does not have sufficient contracted capacity.

1248. DBP proposes to delete clause 8.16 of the existing terms and conditions in relation to use of full haul capacity upstream of CS9. DBP submits that this clause is not suitable for an R1 service. However, given the Authority's determination that the service should be a T1 service, the Authority is of the view that clause 8 of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clause 8.18 of the existing terms and conditions.

Required Amendment 52

Clause 8 of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clauses 8.16 in the 2005 to 2010 terms and conditions in relation to full haul capacity upstream of CS9.

Imbalances (clause 9)

1249. Clause 9 of the proposed revised terms and conditions relates to imbalances and includes provisions for DBP and the shipper to maintain balance, a shipper's accumulated imbalance, notice of the shipper's imbalances, accumulated imbalance limit, balancing in particular circumstances, remedies for breach of imbalance limits, trading in imbalances, cashing out imbalances at end of each gas month and charges not affecting daily delivery.

1250. Proposed changes to clause 9 include:

- a change in the terms for notification of imbalances to the shipper (clause 9.4).
- a change in the terms for dealing with accumulated imbalances in excess of the accumulated imbalance limit and hourly peaks in excess of hourly peaking limits (clauses 9.5 and 10.3); and
- changes to the terms for dealing with the cashing out of imbalances (clause 9.9).

1251. DBP submits that the changes to clause 9 of the proposed revised terms and conditions in relation to imbalances are either to address what works in practice, or are changes of an administrative/grammatical nature.

1252. In its supporting submission #3, Pipeline Services, DBP submits the following.

- The proposed R1 Service is different from the T1 Service in that it does not have the additional behavioural features of the T1 service such as the imbalance rights and extended peaking.
- The reduction in some of the behavioural limits will enable more capacity to be made available for the R1 Service than the T1 Service.
- Since 2006 very few shippers have used the additional behavioural limits. Accordingly, there is no basis to argue that they are likely to be sought by a significant part of the market.
- The practical experience of dealing with the T1 Service terms and conditions has shown that some of the terms and conditions are extremely difficult to administer and apply and do not match up with arrangements under other legislative regimes. An example of this is the imbalance regime. The provisions relating to the timing for the provision of information to enable accumulated imbalances to be calculated do not align with the timing provisions in the Retail Market Rules.
- The original terms and conditions were drafted as part of the SSC. That SSC was drafted in a relatively expedited fashion having regard to the circumstances of the sale in 2004.[511]

Clause 9.4 - Notice of the Shipper's imbalances

1253. DBP submits that the proposed changes to clause 9.4 are for practical reasons. The changes include a change in the time that DBP must provide the shipper notice from before 11:00 to 13:30 and the addition of the words "…and the amounts so notified must, subject to the Operator receiving the information necessary to make an allocation of Gas Deliveries or Receipts or both to shippers as contemplated in clause 6.4(c) be materially accurate" at the end of the clause.

1254. No interested parties commented on this clause. The Authority considers that the proposed changes are reasonable.

Clause 9.5 – Accumulated imbalance limit

1255. Clause 9.5 of the proposed revised terms and conditions relates to the accumulated imbalance limit and provides that the shipper's accumulated imbalance limit for a gas day is 8% of the shipper's contracted capacity across all of the shipper's capacity services for that gas day.

1256. Proposed revisions to clause 9.5 include the removal of the threshold requirement for an adverse impact on the integrity of the operation of the DBNGP before the shipper may incur an excess imbalance charge. DBP submits that the proposed changes to clause 9.5 in relation to accumulated imbalance limits are for practical reasons.

1257. Alinta and Verve Energy consider that:

[511] DBP, 14 April 2010, Confidential supporting submission # 3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au

- the removal of the threshold condition in the existing access arrangement underpinning the imbalance regime is unacceptable, as it effectively provides for payments to be made to DBP where no possible loss has been incurred by DBP nor any adverse impact to the integrity or operation of the pipeline suffered nor liability to another shipper;
- DBP is given the discretion in clause 9.5(c) to levy (or not) the excess imbalance charge with no conditions placed on the exercise of DBP's discretion and this is not acceptable; and
- The existing imbalance regime has been replaced with one that is very penal in its nature, and entirely out of keeping with the arrangements that have been in place since the introduction of third party access to the DBNGP.

1258. Rio Tinto submits the following.

- The deletion of the opening half of clause 9.5(b) and 10.3(a) is not justified. It moves the scheme from one in which DBP can only exercise the "behavioural controls" when there is an operational risk to the pipeline or other shippers, to one in which DBP can exercise these rights arbitrarily in respect of any excursion regardless of the impact it is having.
- The deletion of the old clause 9.5(f), which struck a balance between the operational risk of the pipeline and shippers' operational risk, is also not justified. DBP does not appear to have given any reason for these changes other than that it would be more convenient for DBP.
- The deletion of the existing clauses 9.5(c) and 10.3(c) is also hard to understand as the clauses recognise the unavoidable practical reality that no shipper can instantaneously change its load profile without risking very serious commercial and safety consequences. In the absence of a provision such as this, a shipper doing its utmost in good faith to respond swiftly to a notice may still be penalised.

1259. Clause 9.5(d)(i) of the existing terms and conditions (no charges if the imbalance was caused by a curtailment) reflects another practical reality. That is, an intra-day curtailment imposed on the shipper by DBP will necessarily cause an imbalance, even for a shipper who has acted entirely properly. Rio Tinto sees no reason for its deletion and requests that it be retained.

1260. BHPB submits that DBP proposes to remove a number of protections for shippers in the accumulated imbalances and that there is no justification for this and they should be reinstated. This includes:

- the requirement for a material adverse impact before DBP is able refuse to receive or deliver gas or issue a notice requiring a shipper to reduce its imbalance;
- the concept of deemed best endeavours on the part of the shipper;
- the prohibition on DBP issuing a notice or refusing to receive or deliver gas unless it has first, to the extent reasonable, endeavoured to co-operate with the shipper to ameliorate the impact of the shipper's accumulated imbalance;

- the prohibition which applies in most instances on DBP refusing to receive or deliver gas without having issued a notice (unless due to force majeure or emergency); and
- the exemption from paying an excess imbalance charge if the imbalance arose because the shipper's capacity service was curtailed.[512]

1261. BHPB submits that the proposed changes go beyond those required to accommodate changed legislative requirements, would not be accepted in a competitive market and are contrary to the national gas objective.

1262. The Authority has considered the comments from interested parties in relation to clause 9.5 of the proposed revised terms and conditions and is of the view that, given its decision that the reference service should be a T1 service, and for the reasons advised by shippers against the proposed amendments removing the requirement for an adverse impact on the pipeline or other shippers before DBP can impose a charge against a shipper, clause 9.5 of the proposed revised terms and conditions should be amended to include provisions that are materially the same as those contained in clause 9.5 of the existing terms and conditions.

Required Amendment 53

Clause 9 of the of the proposed revised terms and conditions should be amended to include provisions that are substantially the same as those in clause 9.5 of the existing terms and conditions in relation to accumulated imbalance limit.

Clause 9.6 – Balancing in particular circumstances

1263. Clause 9.6 of the proposed revised terms and conditions provides for balancing in certain circumstances. Clause 9.6(a) provides that if the parties anticipate a failure of the shipper's gas supply (including a failure due to an impending cyclone), the parties may, if they consider it technically practicable and appropriate to do so, agree to increase for a short period the accumulated imbalance limit, to enable the shipper to deposit additional gas in the DBNGP in advance of that failure. Under clause 9.6(c) (subject to clause 9.6(d)) an agreement under clauses 9.6(a) or (b) may be on any terms and conditions the parties consider technically practicable and appropriate.

1264. The main change to clause 9.6 is the new requirement for the agreement to be in writing (which may be contained in an email) and for it to be in place before the shipper seeks to exercise or purport to exercise any rights under it or intended to be granted by it.

1265. DBP submits that the proposed changes to clause 9.6 in relation to balancing in certain circumstances are for practical reasons.

1266. Rio Tinto submits that the current system is more efficient and objects to the change.

512 BHP Billiton, 9 July 2010, Public Submission In Response to the Proposed Revisions to the Dampier to Bunbury Natural Gas Pipeline Access Arrangement.

1267. The Authority is of the view that it may not always be practicable to have the agreement in writing for example if the anticipated failure is due to such circumstances as an impending cyclone and there is limited notice of the impending failure of the shipper's gas supply. For this reason the Authority believes that clause 9.6(c) should be amended to reflect this.

Required Amendment 54

Clause 9.6(c) of the proposed revised terms and conditions, in relation to balancing in particular circumstances, should be amended to remove the requirement that the agreement be in writing.

Clause 9.7 – Remedies for breach of imbalance limits

1268. Clause 9.7 of the proposed revised terms and conditions provides that DBP may not exercise any rights or remedies against the shipper for exceeding the accumulated imbalance limit, other than:

- to recover the excess imbalance charge or excess imbalance charges were permitted by and in accordance with the clause;
- to refuse to receive gas from the shipper at an inlet point or refuse to deliver gas to the shipper at an outlet point so as to bring the shipper's accumulated imbalance within the accumulated imbalance limit; or
- any combination of the rights and remedies as set out above.

1269. The main change to clause 9.7 is the deletion of DBP's ability to exercise rights or remedies against the shipper for exceeding the accumulated imbalance limit for a breach of clause 9.5(b)(iii), as clause 9.5(b)(iii) has been deleted from the proposed revised terms and conditions.

1270. DBP submits that the proposed changes to clause 9.7 in relation to remedies for breach of imbalance limits balancing in certain circumstances are for practical reasons.

1271. No interested parties commented on the proposed changes to clause 9.7. The Authority accepts the changes to clause 9.7 of the proposed revised terms and conditions.

Clause 9.9 – Cashing out imbalances at end of each gas month

1272. Clause 9.9 of the proposed revised terms and conditions establishes the terms for cashing out imbalances at end of each gas month.

1273. The main proposed change to clause 9.9 is that the balancing process is to be undertaken on the first day of each gas month in relation to the shipper's previous month's total gas inputs to, and total gas outputs from, the DBNGP, rather than only at the capacity end date, as in the existing terms and conditions.

1274. DBP submits that the proposed changes to clause 9.9 are for practical reasons. Rio Tinto submits that the current system is more efficient and objects to the change.

1275. The Authority is of the view that, in the absence of substantiation from DBP as to why the proposed change is necessary for practical reasons and in view of the Authority's decision to require terms and conditions substantially consistent with a full haul T1 Service, clause 9.9 of the proposed revised terms and conditions should be amended to be substantially the same as the existing terms and conditions.

Required Amendment 55

Clause 9.6 of the proposed revised terms and conditions, in relation to cashing out imbalances at the end of each gas month, should be amended to be substantially consistent with the existing terms and conditions.

Peaking (clause 10)

1276. Clause 10 of the proposed revised terms and conditions prescribes hourly peaking limits, provides that a shipper must stay within hourly peaking limits, sets out the consequences of exceeding hourly peaking limits, and prescribes remedies for a breach of peaking limits.

1277. Proposed changes to the peaking provisions include changes to hourly peaking limits and the deletion of permissible peaking excursions.

1278. DBP submits that the proposed changes to clause 10 are either due to the nature of the R1 service, are for practical reasons, or are administrative/grammatical changes.

1279. In its supporting submission #3, Pipeline Services, DBP submits the following.

- The proposed R1 Service is different from the T1 Service in that it does not have the additional behavioural features of the T1 service such as the extended peaking and imbalance rights.
- The reduction in some of the behavioural limits will enable more capacity to be made available for the R1 Service than the T1 Service.
- Since 2006 there have been very few shippers who have used the additional behavioural limits. Accordingly, there is no basis to argue that they are likely to be sought by a significant part of the market.[513]

1280. BHPB advises that DBP proposes removing the following protections from the peaking regime:

- the requirement for a material adverse impact before DBP is able to refuse to deliver gas or issue a notice requiring a shipper to reduce its take of gas;
- the concept of deemed best endeavours on the part of the shipper; and
- the permissible peaking excursion clause.

[513] DBP, 14 April 2010, Confidential supporting submission # 3: Pipeline Services. A public version of this submission is available at: www.erawa.com.au

1281. BHPB submits that these protections should be reinstated as there is no justification for removing them. It is of the view that the proposed changes go beyond those required to accommodate changed legislative requirements; they would not be accepted in a competitive market, and are contrary to the national gas objective.

1282. Alinta and Verve Energy both submit the following in relation to the proposed changes to peaking provisions:

- The changes to the hourly peaking provisions, including the deletion of any conditions related to adverse impacts on the integrity and operation of the DBNGP before hourly peaking charges can be levied, and the removal of the outer hourly peaking limit, result in the hourly peaking regime becoming penal in nature.
- In circumstances where breaching the hourly peaking limit does not in any way impact on the integrity nor operation of the DBNGP, nor on any capacity services provided to any other shipper, a charge for breaching such a limit cannot be a genuine pre-estimate of the loss or damage resulting from breaching the relevant threshold and should not be approved.
- DBP does not currently provide accurate hourly data. It is offering a peaking service and a metering information service as non-reference services. The draconian approach to hourly peaking limits and hourly peaking charges for the R1 Service seems designed to create a paying market for its non-reference services; which services are unnecessary at present.

1283. The Authority is of the view that, in view of the Authority's decision to remove the proposed R1 service as a reference service and to include a full haul T1 Service, many of the reasons for the proposed amendments to clause 10 fall away. Further, the Authority considers that the changes to clause 10 of the proposed revised terms and conditions are unlikely to promote the efficient investment in, and the efficient operation and use of, natural gas services for the long term interests of consumers and are likely to be inconsistent with the national gas objective.

Clause 10.3 – Consequences of exceeding hourly peaking limit

1284. Clause 10.3 sets out the consequences for a shipper exceeding the hourly peaking limit. The main change to clause 10.3 is if a shipper exceeds an hourly peaking limit, the operator may issue a notice requiring the shipper to reduce its take of gas, in that or future periods. The proposed revisions require that the shipper must immediately comply, or procure immediate compliance, with the notice (as opposed to using its best endeavours in the existing terms and conditions) so as to cease exceeding the hourly peaking limit; and/or DBP may refuse to deliver gas to the shipper at any outlet point within the relevant pipeline zone until the shipper's hourly quantity is within the hourly peaking limit.

1285. DBP submits that the changes to clause 10.3 of the proposed revised terms and conditions are for practical reasons and are administrative/grammatical changes.

1286. Rio Tinto submits that the current system is more efficient and objects to the changes.

1287. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service and for the reasons set out in the second part of paragraph 1283 of this draft decision, the Authority is of the view that clause 10.3 of the proposed revised terms and conditions should be amended to be materially consistent with clause 10.3 of the existing terms and conditions and the requirement that a "shipper must use best endeavours" to comply with a notice issued under clause 10.3 should be reinstated.

Required Amendment 56

Clause 10.3 of the proposed revised terms and conditions, in relation to consequences of exceeding hourly peaking limits, should be amended to be substantially consistent with clause 10.3 of the existing terms and conditions and the words "shipper must use best endeavours to comply with a notice issued under clause 10.3" reinstated.

Outer hourly peaking limit (clause 10.4 of the 2005 to 2010 terms and conditions)

1288. DBP proposes to delete clause 10.4 of the existing terms and conditions which prescribes outer hourly peaking limits. DBP submits that clause 10.4 is not appropriate for the proposed R1 Service.[514]

1289. DBP also submits that the pipeline's design assumptions are such that, if these additional rights are afforded to shippers, it sterilises so much capacity that it is an inefficient allocation of resources.[515]

1290. The Authority is not convinced by the material put forward by DBP that the effect of clause 10.4 will be to sterilise a substantial amount of pipeline capacity.

1291. Further, given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service and for the reasons set out in the second part of paragraph 1283 of this draft decision, the Authority is of the view that the proposed terms and conditions should contain provisions that are substantially consistent with clause 10.4 of the existing terms and conditions in relation to the outer hourly peaking limit.

Required Amendment 57

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 10.4 of the existing terms and conditions in relation to outer hourly peaking limit.

514 DBP, 6 August 2010, Supporting Submission #26, Response to Third Party Submissions.

515 DBP, 14 April 2010, Supporting Submission #5.

Permissible peaking excursion (clause 10.7 of the 2005 to 2010 terms and conditions)

1292. DBP proposes to delete clause 10.7 of the existing terms and conditions in relation to a permissible peaking excursion which means that DBP must not refuse to deliver gas if a shipper is not exceeding its outer hourly peaking limit.

1293. DBP submits that clause 10.7 is not appropriate for the R1 Service. DBP also submits that the pipeline's design assumptions are such that if these additional rights are afforded to shippers, it sterilizes so much capacity that it is an inefficient allocation of resources.

1294. BHP Billiton is of the view that this clause should be retained as it provides a protection for the shipper that DBP has no justification for removing. In an email to the Secretariat, 29 November 2010, BHP Billiton advises that it objects to the deletion of clause 10.7 as it would allow DBP to selectively refuse to deliver gas and discriminate between shippers and this is inconsistent with the national gas objective.

1295. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed terms and conditions should contain provisions that are materially consistent with clause 10.7 of the existing terms and conditions in relation to permissible peaking excursion.

Required Amendment 58

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 10.7 of the existing terms and conditions in relation to permissible peaking excursion.

Overrun (clause 11)

1296. Clause 11 of the proposed revised terms and conditions relates to overrun charges and provides that, in respect of each GJ of overrun gas received by a shipper on a gas day, the shipper must pay an overrun charge calculated by applying the overrun rate to the total overrun gas received by the shipper on that gas day.

1297. DBP submits that the proposed changes to clause 11 of the proposed revised terms and conditions are either for practical reasons or administrative/grammatical changes.

Clause 11.1 – Overrun charge

1298. DBP proposes to change the overrun rate in clause 11(b)(i) of the proposed revised terms and conditions from 115 per cent in the existing T1 Service to 500 per cent in the proposed R1 Service. DBP submits that the changes to the overrun rate are for practical reasons. However, DBP has not provided any further substantiation or justification for this large increase in the overrun rate.

1299. BHP Billiton submits that:

- the proposed changes go beyond those required to accommodate changed legislative requirements and result in a much higher overrun rate than would be negotiated in a competitive market; and
- the changes do not promote the efficient operation and use of natural gas services for the long term interests of consumers and should be rejected.

1300. Alinta and Verve Energy both submit:

- that the overrun rate is twice the unavailable overrun charge, which purports to deal with behaviour more detrimental to the pipeline; and
- without any justification, a more than four-fold increase in the overrun rate is completely unacceptable, paying 750% of the reference tariff on the same quantity of gas must be considered an unenforceable penalty.

1301. Rio Tinto also submits that the fourfold increase is not justifiable and that it should remain at the current percentage, or as applicable to the T1, B1 or P1 tariff.

1302. DBP has not presented any evidence to justify the need this increase; for example, evidence of operational reasons why overruns have a greater impact on the operation of the pipeline justifying a greater penalty to discourage this behaviour. In the absence of such evidence, the Authority does not approve the increase in the charge.

1303. The Authority has considered the views of interested parties outlined above and agrees that, without substantiation or justification, the four fold increase is too high. Further, given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed terms and conditions should contain provisions that are substantially consistent with clause 11.1 of the existing terms and conditions in relation to the overrun charge.

Required Amendment 59

The proposed terms and conditions should contain provisions that are substantially consistent with clause 11.1 of the existing terms and conditions in relation to the overrun charge.

Clause 11.2 – Unavailability notice

1304. Clause 11.2 of the proposed revised terms and conditions relates to the issuing of an Unavailability Notice. Clause 11.2 provides that DBP may at any time, acting as a reasonable and prudent person, give an unavailability notice to the shipper that overrun gas is unavailable to the shipper, or is only available to the shipper to a limited extent, for one or more gas days.

1305. Under the exiting terms and conditions DBP can give an unavailability notice to the shipper but only to the extent that the shipper overrun will impact or is likely to impact on another shipper's entitlement to its daily nomination for T1 capacity, firm service, any other reserved service or scheduled spot capacity. That pre-condition to issuing an unavailability notice has been deleted.

1306. DBP submits that the proposed changes to clause 11.2 of the proposed revised terms and conditions are for practical reasons.

1307. Rio Tinto submits that, as with peaking and balancing, it objects to the removal of the threshold test that overrun must be materially impacting on other shippers, and requests that the deleted words be reinstated.

1308. Alinta and Verve Energy's views on the proposed changes to clause 11.2 of the terms and conditions are similar to their views in relation to the excess imbalance charges and hourly peaking charges. In Verve Energy and Alinta's opinion:

- the penalties for breaching certain thresholds are not related at all to the actual impact on the DBNGP or other shippers' capacity; and cannot be accepted as a genuine pre-estimate of damage or loss suffered by DBP due to the relevant gas usage;
- the penalties become particularly hard to accept when they are increased arbitrarily and to a very significant extent (refer comment above).

1309. DBP has not provided any explanation of what are the 'practical reasons' for the proposed change to clause 11.2. The Authority agrees with the concerns raised by Rio Tinto, Alinta and Verve Energy. Further, given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed terms and conditions should contain provisions that are substantially consistent with clause 11.2 of the existing terms and conditions in relation to an unavailability notice.

Required Amendment 60

The proposed terms and conditions should contain provisions that are substantially consistent with clause 11.2 of the existing terms and conditions in relation to an unavailability notice.

Clause 11.4 – Compliance with unavailability notice

1310. Clause 11.4 provides that the shipper must as soon as practicable comply, or procure compliance, with an unavailability notice, by ensuring that the total of its overrun gas, for each gas day to which the unavailability notice applies, does not exceed the quantity of overrun gas indicated by the unavailability notice to be available to the shipper.

1311. The main change to this clause 11.4 is that it now also includes a requirement that as soon as practicable after receipt of the notice to comply, the shipper must provide notice to DBP advising of the measures being taken to ensure compliance with 11.4(a)(i).

1312. DBP submits that the proposed changes to clause 11.4 of the proposed revised terms and conditions are for practical reasons.

1313. No interested parties commented on the proposed changes to clause 11.4 of the proposed revised terms and conditions. The Authority is of the view that the proposed changes to clause 11.4 are reasonable.

Clause 11.7 – Saving and damages

1314. Clause 11.7 of the proposed revised terms and conditions relates to a shipper's liability to DBP for any direct damage suffered by DBP which is caused by, or arises out of, the shipper's failure to comply with an unavailability notice.

1315. DBP proposes to make the following change to clause 11.(c) of the terms and conditions:

Saving and damages

(c) The Shipper is ~~not~~ liable to pay the Overrun Charge under clause 11.1 and the Unavailable Overrun Charge under clause 11.6 in respect of the same quantity of Overrun Gas.

1316. BHP Billiton submits that by deleting the word ‘not’, DBP appears to be proposing double jeopardy for the same offence. BHP Billiton is of the view that this is neither fair nor efficient and request that the word “not” be retained.

1317. DBP submits that the proposed changes to clause 11.7 of the proposed revised terms and conditions, in relation to savings and damages, are for practical reasons.

1318. The Authority is not convinced the proposed amendment is necessary for practical reasons and DBP provides no further evidence or explanation. The Authority accepts the submissions of BHP Billiton and is of the view that the word “not” should be reinstated in clause 11.7(c) to avoid a shipper being charged twice for the same conduct.

Required Amendment 61

Clause 11.7(c) of the proposed terms and conditions, in relation to savings and damages, should be amended to reinstate the word “not”.

Additional rights and obligations of operator (clause 12)

1319. Clause 12 of the proposed revised terms and conditions relates to additional rights and commingling of gas, processing, operation of the pipeline system, and the delivery of gas.

1320. The main change to clause 12 is the removal of the requirement in clause 12.4 of the existing terms and conditions that DBP may use any means other than the DBNGP for delivery only where there is no extra cost or risk to the shipper.

1321. DBP submits that the proposed changes to clause 12 of the proposed revised terms and conditions, in relation to additional rights and obligations for DBP, are either for practical reasons or administrative/grammatical changes.

Clause 12.1 – Commingling of gas

1322. Clause 12.1 of the proposed revised terms and conditions provides that DBP will have the right to commingle the gas delivered by the shipper at an inlet point with other gas in the DBNGP during transportation and is entitled to deliver different molecules to the shipper at the outlet points "from those received at the inlet points".

1323. The changes to this clause are minor and comprise mainly the addition of the words "from those received at the inlet points" at the end of the clause. DBP submits that the proposed changes to clause 12.1 of the proposed revised terms and conditions are for practical reasons.

1324. No interested parties commented on clause 12.1 of the proposed revised terms and conditions. The Authority considers that the proposed changes are reasonable.

Clause 12.4 – Delivery of gas

1325. Clause 12.4 of the proposed revised terms and conditions provides that DBP may satisfy its obligation to enable gas to be delivered to the shipper by using any means other than the DBNGP provided that DBP otherwise meets its obligations under the contract.

1326. The proposed change to clause 12.4 is the removal of the requirement in the existing terms and conditions that DBP may use any means other than the DBNGP for delivery only where "there is no extra cost or risk to shipper in doing so".

1327. DBP submits that the changes to clause 12.4 of the proposed revised terms and conditions, in relation to delivery of gas, are for practical reasons.

1328. Alinta and Verve Energy submit that the requirement in the existing terms and conditions that DBP may use any means other than the DBNGP for delivery only where "there is no extra cost or risk to shipper in doing so" should be reinstated.

1329. The Authority agrees with Alinta and Verve Energy that DBP should be able to use any means other than the DBNGP for delivery only where there is no extra cost or risk to shipper in doing so.

Required Amendment 62

The proposed revised terms and conditions should be amended to include a provision that is substantially the same as clause 12.4(b) of the existing terms and conditions, in relation to the delivery of gas Clause 12 should therefore provide that the operator may satisfy its obligation to enable gas to be delivered to the shipper by using any means other than the DBNGP provided that it otherwise meets its obligations under the contract and only where there is no extra cost or risk to shipper in doing so.

Relocation (clause 14)

1330. Clause 14 of the proposed revised terms and conditions relates to relocation of contracted capacity and includes provisions for a request for relocation of contracted capacity, an assessment of a requested relocation, provisions for when the operator is to notify the shipper of a request, and whether the requested relocation is an authorised relocation or not .

1331. DBP submits that the changes to clause 14 of the proposed revised terms and conditions, in relation to relocation of contracted capacity, are either for practical reasons or administrative/grammatical changes.

Clause 14.2 – Assessment of requested relocation

1332. Clause 14.2 of the proposed revised terms and conditions relates to the assessment of requested relocation for contracted capacity and the requirement for new inlet points to satisfy DBP's technical and operational requirements.

1333. Clause 14.2(b)(i)(A) of the proposed revised terms and conditions relates to conditions under which a requested relocation of contracted capacity is not deemed an authorised relocation by DBP. The proposed revised terms and conditions add a condition that it is not an authorised relocation if the contracted capacity exceeds "the safe operating capability of the part of the DBNGP at the point at which the new inlet point is located".

1334. DBP submits that the changes to clause 14.2 are for practical reasons.

1335. Rio Tinto submits that this new condition should be removed as it creates "a substantial and vague new limitation, which seems unnecessary in light of the already broad and subjective test in clause 14.2(b)(ii)". Clause 14.2(b)(ii) provides that a requested relocation would not be authorised if, in the opinion of the operator, as a reasonable and prudent person, if it would not be operationally feasible.

1336. The Authority agrees with Rio Tinto that the proposed new condition is unnecessary in light of the already broad and subjective test in clause 14.2(b)(ii) which permits the operator to take into account the safe operating capability of the relevant part of the DBP.

1337. Rio Tinto advises that it accepts that a relocation which materially lengthens the haul should be treated as not authorised and hence not subject to negotiation. However, Rio Tinto is of the view that the 2 km allowance is an established recognition of the fact that some relocations between adjacent points might otherwise be classified as not authorised because they technically lengthen the haul. Rio Tinto advises that this may be the case even if the haul is lengthened by as little as 100m, and even though in practical terms there is no adverse impact on the pipeline. Rio Tinto advises that a 2 km allowance permits non-impacting relocations to proceed and that this is a significant contribution to shippers' efficient management of their gas and capacity portfolios as mines, markets and loads change.

1338. Rio Tinto submits that if DBP can show clear operational reasons why the 2 km threshold is genuinely too large, then the Authority should examine the pipeline configuration to see what shorter distance could be set and still catch the various adjacent sets of points.

1339. Alinta and Verve Energy also both submit that a new outlet point should be an authorised relocation if the new outlet point is upstream of the existing outlet point or no greater than 2 km downstream of the existing outlet point.

1340. DBP in its response to third party submissions states that it cannot agree with this change but offers no reasoning.

1341. The Authority has considered the views of DBP, Rio Tinto, Alinta and Verve Energy and is of the opinion that in the absence of further sufficient justification for a change from DBP the threshold of 2 km should remain for a new outlet point to be an authorised relocation if the existing outlet point is no greater than 2 km downstream of the existing outlet point.

1342. Alinta and Verve Energy submit that the word "proposed" in both sub- clauses 14.2(c)(ii) and 14.2(d)(ii), in relation to the assessment of a requested relocation and the need for a "proposed" inlet point to satisfy DBP's technical and operational requirements should be replaced by the word "planned". Verve Energy and Alinta also both submit that the DBP's technical and operational requirements should be set out in detail or reference made to the specific provisions of the contract in which the requirements are set out.

1343. In its response to third party submissions, DBP advises that it intentionally used the word "proposed" and considers it to be a more appropriate word than "planned" in the context of this clause. DBP also submits that it may not be feasible to set out the detail of what may be DBP's technical and operational requirements in a particular circumstance at a future date.[516]

1344. The Authority has noted Verve Energy and Alinta's view on clause 14.2(c)(ii) and 14.2(d)(ii) of the proposed revised terms and conditions and DBP's response and agrees with DBP's response.[517]

Required Amendment 63

The proposed revised terms and conditions should be amended to contain provisions that are substantially consistent with clause 14.2(d)(i) of the existing terms and conditions in relation to the assessment of requested relocation of contracted capacity.

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516 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

517 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

Metering (clause 15)

1345. Clause 15 establishes the proposed revised terms and conditions for metering including the shipper's responsibility, DBP's responsibility, provisions for metering uncertainty, provisions for primary metering equipment, changes to requirements for metering equipment, approval of inlet metering equipment and adjustment or replacement of defective metering equipment.

1346. Changes to clause 15 of the proposed revised terms and conditions include:

- the inclusion of additional gas parameters in the metering requirements; and
- the deletion of provisions relating to the availability of information for distribution network shippers.

1347. DBP submits that the proposed changes to clause 15 of the proposed revised terms and conditions are either for practical reasons or are administrative/grammatical changes.

Clause 15.1 – Shippers' responsibility

1348. Clause 15.1 of the proposed revised terms and conditions sets out the terms for the shipper's responsibilities in relation to metering and provides that the shipper must either itself or by procuring another party to do so, at the shipper's expense, supply, install, operate and maintain inlet metering equipment at each inlet station. The main change to this clause is that the words "at the shipper's expense" have been added in relation to a shipper procuring another party to install, operate or maintain the metering equipment.

1349. DBP submits that the changes to clause 15.1 of the proposed revised terms and conditions, in relation to metering and shippers' responsibility, are for practical reasons.

1350. No interested party commented on the proposed changes to clause 15.1. The Authority is satisfied that the proposed changes to clause 15.1 of the proposed revised terms and conditions are reasonable.

Clause 15.2 – Operator's responsibility

1351. Clause 15.2 of the proposed revised terms and conditions sets out the terms for DBP's responsibilities in relation to metering and provides that DBP must either itself or by procuring another party to do so, at the shipper's expense, supply, install, operate and maintain outlet metering equipment at each outlet station in good working order and condition and in accordance with the standard of a reasonable and prudent person.

1352. The main change to clause 15.2 is the addition of the words "either itself or by procuring another party to do so" in relation to the requirement for the shipper's at its expense to supply, install, operate and maintain outlet metering equipment at each outlet station in good working order.

1353. DBP submits that the changes to clause 15.2 of the proposed revised terms and conditions, in relation to metering and operator's responsibility, are for practical reasons. No interested party commented on the proposed changes to clause 15.2 of the proposed revised terms and conditions.

1354. The Authority is satisfied that the proposed changes to clause 15.2 of the proposed revised terms and conditions are reasonable.

Clause 15.3 – Metering uncertainty

1355. Clause 15.3 of the proposed revised terms and conditions sets out provisions for metering uncertainty and sets out terms for the design, adjustment and operation of primary metering equipment so as to achieve a measurement within a maximum uncertainty.

1356. The main change to this clause is that DBP proposes to reduce the maximum metering uncertainty from 1 per cent to 0.75 per cent.

1357. DBP submits that the changes to clause 15.3 of the proposed revised terms and conditions are for practical reasons.

1358. Alinta and Verve Energy both submit that the proposed changes to clause 15.3(a)(i)(A), whereby a maximum metering uncertainty has been reduced from 1 per cent to 0.75 per cent, should be rejected.

1359. In its response to third party submissions, DBP advises that this change was made to apply a more internationally accepted approach to uncertainty. DBP believes more accurate metering would benefit shippers and allow DBP to have better control of unaccounted for gas.[518]

1360. The Authority has considered the views of interested parties and DBP's response and is of the view that DBP has not established a benefit that may justify additional costs potentially being imposed on users by a more stringent metering uncertainty. In the absence of further technical reasoning from DBP the Authority does not agree to the proposed change to reduce the maximum metering uncertainty from 1 per cent to 0.75 per cent.

Required Amendment 64

Clause 15.3 of the proposed revised terms and conditions, in relation to metering uncertainty, should be amended to be substantially the same as the existing terms and conditions.

Clause 15.4 – Primary metering equipment

1361. Clause 15.4 of the proposed revised terms and conditions relates to primary metering equipment. Proposed changes to clause 15.4(c) include the inclusion of additional gas parameters in metering requirements. DBP submits that the changes to clause 15.4 of the proposed revised terms and conditions are for practical reasons.

518 DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

1362. Clause 15.4(a)(i)(C) is a new clause which requires primary metering equipment to continuously compute and record any information required by DBP, from time to time, to assist DBP comply with any Law. Verve Energy and Alinta both submit that the recording of this information should be recorded at DBP's cost.

1363. Rio Tinto submits that:

- clause 15.4(a)(i)(C) exposes the shipper to indeterminate parameters in metering and an open-ended liability for upgrading the equipment;
- this requirement is already regulated adequately in clause 15.6, with an established apportionment of risk between DBP and the shipper; and
- the Authority and DBP should consider whether the grandfathering rules in clause 6.17 may need to be expanded or clarified, or have a new cut off date inserted, to ensure that the changes in clause 15.4(c) do not accidentally require the upgrade of all the existing facilities on the DBNGP.

1364. In its response to third party submissions, DBP advises that this is a necessary and reasonable operating expense which should be recoverable from the shipper.[519]

1365. The Authority has considered the views of interested parties and DBP's response and is of the view that given that clause 15.4(a)(i)(C) should apply to enable DBP to require information reasonably necessary to enable it to comply with a Law.

Required Amendment 65

Clause 15.4(a)(i)(c) of the proposed revised terms and conditions should be amended to insert the word "reasonable" after the words "any information".

Clause 15.5 – Provision of information to shipper

1366. Clause 15.5 of the proposed revised terms and conditions relates to the provision of information to the shipper and the circumstance under which DBP must, on request and at the expense and risk of the shipper, make available to the shipper access to certain information.

1367. The main proposed change to clause 15.4 is that clauses 15.5(e), (f) and (g) of the existing terms and conditions have been deleted. These provisions relate to the availability of information for distribution network shippers. DBP proposed to delete the following from clause 15.4.

[519] DBP, 6 August 2010, Confidential supporting submission # 26: Response to 3rd Party Submissions. A public version of this submission is available at: www.erawa.com.au

(e) Operator must make available to Shipper via the CRS or a similar communications system as soon as practicable after receiving from Networks the information referred to in clause 33(1) of the Operating Arrangement, but in any event no later than 72 hours after the end of the Gas Day to which the information relates, the verified quantity of Gas:

(i) Received by Shipper in a Gas Day at each Physical Gate Point; and

(ii) Received by Shipper in a Gas Day aggregated across all outlet points including all Physical Gate Points.

(f) Operator must make available to Shipper via the CRS or a similar communications system within 5 hours after the end of a Gas Day the verified quantity of Gas:

(i) Received by Shipper in that Gas Day at each Physical Gate Point; and

(ii) Received by Shipper aggregated across all outlet points including all Physical Gate Points.

(g) Clauses 15.5(e) and (f) only apply for as long as Shipper is a Distribution Networks Shipper.

1368. DBP submits that the changes to clause 15.5 of the proposed revised terms and conditions are for practical reasons.

1369. Alinta and Verve Energy submit that these provisions should be reinstated for the benefit of distribution network shippers. In its response to third party submissions, DBP submits that if shippers want this information, they should negotiate a data services agreement. DBP advises that, to date, all data that has been requested by a shipper has been provided by DBP under a data services agreement.

1370. The Authority has considered the views of interested parties and DBP's response and is of the view that it is not reasonable or efficient for individual shippers to be required to negotiate a data services agreement to obtain the relevant information set out in clause 15.5(e), (f) and (g).

Required Amendment 66

Clause 15.5 of the proposed revised terms and conditions, in relation to the provision of information to shippers, should be amended to reinstate sub-clauses (e), (f) and (g).

Clause 15.12 – Adjustment or replacement of defective equipment

1371. Clause 15.12 of the proposed revised terms and conditions relates to the adjustment or replacement of defective equipment. The proposed changes to this clause are that words have been rearranged. The meaning does not appear to be affected. DBP submits the changes are for practical reasons.

1372. No interested parties commented on clause 15.12 of the proposed revised terms and conditions. The Authority considers that the proposed changes are reasonable.

Clause 15.13 – Inaccurate equipment

1373. Clause 15.13 of the proposed revised terms and conditions relate to inaccurate equipment. The only proposed changes to this clause are the rearranging of words. The meaning does not appear to be affected. DBP submits that the changes are administrative or grammatical changes.

1374. Alinta and Verve Energy note some typographical errors in clauses 15.13(b) & 15.13(c) relating to primary metering equipment accuracy and verification. DBP in its response to third party submission agrees that this should be amended.

Clause 15.16 – Unused outlet points

1375. Clause 15.16 of the proposed revised terms and conditions relates to unused outlet points. The changes to clause 15.13 are not material changes rather only that the words have been rearranged. DBP submits that they are for practical reasons.

1376. Rio Tinto submits, as a minor point, the charges under clause 6.12 should only apply in 15.16(d) in respect of new expenditure.

1377. DBP submits that if it is required to recommission an outlet or inlet station, then a shipper should in those instances, be treated no differently to a shipper seeking access to a new outlet station and therefore a maintenance charge should be payable by the shipper.[520]

1378. The Authority has considered Rio Tinto's view in relation to clause 15.16 of the proposed revised terms and conditions but is of the view that it is reasonable that a recommissioned outlet or inlet station should be subject to the same maintenance charges as a new outlet station. The Authority accepts the proposed changes to clause 15.16 of the proposed revised terms and conditions.

Curtailment (clause 17)

1379. Clause 17 of the proposed revised terms and conditions establishes terms relating to curtailment. DBP proposes various changes to these terms that it says are in the nature of administrative changes, changes in response to practical experience, or changes in recognition of the type of service that is the R1 Service. Substantive changes include:

- the removal of terms which establish that a reduction in gas transmission capacity and planned maintenance are a basis for curtailment (clause 17.2(c) and (d) of the 2005 to 2010 terms and conditions);
- the inclusion of additional terms for providing notice of curtailment (proposed clause 17.6);
- changes to terms relating to the priority of curtailment of services (proposed clause 17.9); and
- changes to terms relating to the apportionment of a shipper's curtailments (proposed clause 17.10).

[520] DBP Confidential Submission #27.

Clause 17.2 – Curtailment generally

1380. Clause 17.2 of the proposed terms and conditions sets out terms for curtailment generally. DBP proposes to narrow these terms by removing terms relating to gas transmission capacity and planned maintenance. DBP submits that the proposed change is for reason of what works in practice.

> 17.2 The Operator may curtail the provision of the Capacity Services to the Shipper from time to time to the extent the Operator as a Reasonable and Prudent Person believes it is necessary to Curtail:
>
> (a) if there is an event of Force Majeure where the Operator is the Affected Party;
>
> (b) whenever it needs to undertake any Major Works;
>
> ~~(c) by reason of, or in response to a reduction in Gas Transmission Capacity caused by the default, negligence, breach of contractual term or other misconduct of Shipper;~~
>
> ~~(d) for any Planned Maintenance;~~ and
>
> (c) in circumstances where the Operator, acting as a Reasonable and Prudent Person, determines for any other reason (including to avoid or lessen a threat of danger to the life, health or property of any person or to preserve the operational integrity of the DBNGP) that a Curtailment is desirable.

1381. Alinta and Verve Energy each submit that the approach, as outlined in the old clause 17.2(c), should be retained; otherwise the R1 Service is devalued, which must be reflected in a lower tariff than the T1 tariff.

1382. With respect to the proposed changes to clause 17.2 Rio Tinto notes that DBP has proposed to change the treatment of planned maintenance by rolling it into the definition of “major works”. Rio Tinto is of the opinion that this is a material commercial change which it opposes. Furthermore, Rio Tinto notes that a curtailment for planned maintenance under old clause 17.2(c), did not come with the ‘no liability’ provisions of clause 17.3(b)(ii) and counted towards the 2 per cent permissible curtailment limit because it was not listed as an exclusion in clause 17.3(c)(i). The proposed changes to clause 17.2 could result in scheduled planned maintenance that results in more than 2 per cent of outages per year; potentially requiring shippers to incur more costs for alternative fuels, such as diesel.

1383. In response to these third party submissions, DBP makes reference to the information in section 4 of its supporting submission (#3) on pipeline services[521], which outlines the reasons for differences between the R1 and T1 behavioural rights.

[521] DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4). A public version of this submission is available at: www.erawa.com.au

1384. The Authority has given separate consideration to DBP's proposed changes to the definition of "major works" at paragraph 1014 and following of this draft decision. Matters relating to the 'no liability' provisions of clause 17.3(b) and permissible curtailment limit of clause 17.3(c) are considered below. Consistent with these considerations, and the Authority's decision not to allow the R1 Service, the Authority is of the view that the old clause 17.2(c) should be retained.

Required Amendment 67

Clause 17.2, in relation to curtailment generally, should be amended to reinstate sub-clauses (c) and (d) in the existing terms and conditions.

Clause 17.3 – Curtailment without liability

1385. Clause 17.3 of the proposed terms and conditions outlines the circumstances where curtailment is to occur without liability. In particular, clause 17.3(b) provides that the operator has no liability to the shipper, except as may be provided in clause 17.4 ("Refund of Capacity Reservation Charge"), for a curtailment in any of the following circumstances:

- where the duration of the curtailment, together with the aggregate duration of all other curtailments during the gas year does not cause the permissible curtailment limit to be exceeded (proposed clause 17.3(b)(i));
- where the curtailment is in accordance with clauses 17.2(a) or 17.2(b) (proposed clause 17.3(b)(ii)); or
- where clause 17.5 ("Operator's rights to refuse to Receive or Deliver Gas") provides that the circumstance is not to be regarded as a curtailment (proposed clause 17.3(b)(iii)).

1386. Both Alinta and Verve Energy raise issues similar to those raised by Rio Tinto with respect to curtailment without liability including a curtailment for "major works", which now includes planned maintenance. Alinta and Verve Energy each submit that curtailment for planned maintenance has previously counted towards the permissible curtailment limit and to change this is a significant devaluation of the R1 Service. Planned maintenance should be treated separately to major works in relation to curtailments without liability.

1387. In its response to third parties submissions, DBP refers to the information provided in response to third party comments on the proposed changes to the definition of "major works".

1388. As indicated at paragraph 1384 above, the Authority has given separate consideration to DBP's proposed changes to the definition of "major works" at paragraph 1014 and following of this draft decision. Consistent with these considerations the Authority is of the view that planned maintenance should not be included in curtailment without liability.

Required Amendment 68

Clause 17.3(b) of the proposed revised terms and conditions, in relation to curtailment without liability, should be amended to be substantially the same terms as clause 17.3(b) in the existing terms and conditions.

Clause 17.5 – Operator's right to refuse to receive or deliver gas

1389. Clause 17.5 of the proposed revised terms and conditions relates to the operator's rights to refuse to receive or deliver gas. DBP submits that the proposed changes to clause 17.5 are administrative or grammatical changes. The main change is that DBP proposed to delete the words the words "Subject to clauses 5.5 and 5.9…" at the begging of the clause.

1390. In light of the Authority's required amendments to clauses 5.5 and 5.9 of the proposed revised terms and conditions to make them subject to clause 17 of the proposed revised terms and conditions, the Authority requires that the words "Subject to clauses 5.5 and 5.9,…" to be reinstated at the beginning of clause 17.5 of the propose revised terms and conditions.

Required Amendment 69

Clause 17.5 of the proposed revised terms and conditions, in relation to the operator's right to refuse to receive to deliver gas, should be amended so that the words "Subject to clauses 5.5 and 5.9,…" are reinstated at the beginning of clause 17.5.

Clause 17.6 – Curtailment notice

1391. Clause 17.6 of the proposed terms and conditions sets out terms relating to the provision of a curtailment notice. DBP proposes to revise and include additional terms under clause 17.6(b), for the provision of such notices and submits that these new terms are for reasons of what works in practice.

(b) ~~Operator must use reasonable endeavours to give Shipper a Curtailment Notice a reasonable period in advance of the starting time of the Curtailment, and in any event (other than when due to Force Majeure or by reason of an emergency it is unable to do so) must give the Curtailment Notice at least one hour before the starting time of the Curtailment. In the case of Major Works, reasonable notice is 90 days notice.~~

(i) Where the reason for the Curtailment is Major Works, the Operator must give the Shipper:

(A) an initial notice (Initial Notice) at least 60 days in advance of the starting time of the Curtailment; and

(B) a Curtailment Notice no later than one Gas Day before the Gas Day on which the Curtailment commences.

(ii) In any case other than one described in clause 17.6(b)(i):

(A) subject to clause 17.6(b)(ii)(B), the Operator must give the Shipper a Curtailment Notice at least one hour in advance of the starting time of the Curtailment; and

(B) where as a result of Force Majeure or by reason of an emergency it is not reasonably possible to give a Curtailment Notice at least one hour in advance of the starting time of the Curtailment, the Operator must give the Shipper a Curtailment Notice as soon as it is practicable to do so, whether that is before or after the starting time of the Curtailment.

1392. Rio Tinto submitted that it supports DBP's redraft of clause 17.6, but notes that the former requirement of "a reasonable period in advance", in addition to the minimum one hour, has not been included in proposed clause 17.6(b)(ii)(A). Rio Tinto requests that that this requirement be included.

1393. In response to Rio Tinto's submission, DBP submits that the previous drafting of clause 17.3(b) created confusion. DBP submits that the proposed amended dratting addresses this confusion.

1394. The Authority considers that what is a reasonable period of notice is likely to vary in different circumstances so that, in a case other than for Major Works, DBP should be required to provide reasonable notice but, in any event for certainty, at least one hour's notice in advance of the curtailment.

Required Amendment 70

Clause 17.6(b)(ii)(A) of the proposed revised terms and conditions should be amended to insert after the word "must" the words "use its best endeavours to" and after the word "Notice", the words "a reasonable period in advance of the stating time of the curtailment but in any event".

Clause 17.7 – Content of a curtailment notice and initial notice

1395. Clause 17.7 of the proposed terms and conditions establish requirements for the content of a "curtailment notice" and "initial notice". DBP proposes to insert a new clause 17.7(b) requiring an initial notice to specify the operator's estimate of the starting time of the curtailment and the portion of the shipper's contracted capacity that is to be curtailed. DBP submits that this change is for reason of what works in practice.

1396. Alinta and Verve Energy each submit that an initial notice should also be required to include the reasons for the curtailment and, if the operator is not able to provide reasons at that time, an explanation as to why not. Alinta and Verve Energy are both of the opinion that, given the planning involved in major works, the operator will have information that can be provided to the shipper as to why the shipper's capacity is to be curtailed.

1397. In its response to third party submissions, DBP submits that the reason for the initial notice is known; the initial notice is for "major works" (otherwise an initial notice would not be required).

1398. The Authority notes that clause 17.6(b)(i)(A) of the proposed terms and conditions states that "where the reason for the curtailment is major works, the operator must give the shipper an initial notice at least 60 days in advance of the starting time for the curtailment". The Authority is satisfied that clause 17.6(b)(i)(A) adequately establishes the reason for an initial notice, being major works, as submitted by DBP in its response to third party submissions.

1399. Given clause 17.6(b)(i)(A), the Authority believes that the submissions of Alinta and Verve Energy are seeking to establish requirements for the operator to provide additional information related to the major works, which causes the initial notice to be issued.

1400. The Authority considers that it is reasonable for the operator be required to provide information related to the major works that triggers the need for an initial notice under clause 17.6(b)(i)(A).

Required Amendment 71

Clause 17.7(b) of the proposed revised terms and conditions, in relation to the content of a curtailment notice and initial notice, should be amended to require an initial notice to specify the operator's reasons for, and a description of, the major works that has initiated the need for an initial notice to be issued under clause 17.6(b)(i)(A).

Clause 17.8 – Compliance with curtailment notice

1401. Clause 17.8 of the proposed terms and conditions sets out requirements for compliance with the curtailment notice. DBP proposes to remove the following requirement from this clause; indicating that the change is for reason of what works in practice.

> Other than when due to Force Majeure or by reason of an emergency it is unable to do so, Operator is to give effect to a Curtailment by a Curtailment Notice instead of, or prior to, doing so physically under clause 17.8(c).[522]

1402. Alinta and Verve Energy both submit that this requirement should be reinstated. No additional reasoning is provided.

1403. Rio Tinto questions the removal of this requirement and submits that physical curtailment can pose safety and operational risks, and is something of a 'nuclear' response. Rio Tinto is of the view that the requirement reflects operational practice and would not appear to be much of an imposition on DBP.

522 Clause 17.8(f) of the 2005 to 2010 terms and conditions for the T1 Service.

1404. In its response to third party submissions, DBP makes reference to the type of service that is being proposed, that is, the proposed R1 Service is not a T1 Service and does not provide all the rights of a T1 Service. DBP submits that the reasons for the differences between the R1 Service and T1 Service are explained in its supporting submission (#3) on pipeline services.[523]

1405. Having regard to DBP's response to third party submissions, the Authority is of the opinion that DBP's proposal to remove requirements from clause 17.8 is in recognition of the type of service that is the R1 Service (as opposed to reasons of what works in practice). Therefore, consistent with the Authority's decision to require amendments to the proposed revised access arrangement to remove the R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that clause 17.8 should be substantially the same as clause 17.8 of the 2005 to 2010 terms and conditions for the T1 Service. The Authority also accepts Rio Tinto's submissions in relation to the effect of physical curtailment without notice.

Required Amendment 72

Clause 17.8 of the proposed revised terms and conditions, in relation to compliance with a curtailment notice, should be amended to be substantially the same as clause 17.8 of the existing terms and conditions.

Clause 17.9 – Priority of curtailment

1406. Clause 17.9 of the proposed terms and conditions sets out terms relating to the priority of curtailment. DBP proposes several changes to this clause that are in recognition of the type of service that is the R1 Service, and/or changes to address terms that are not appropriate for an R1 Service. Such changes include the removal of terms relating to the "aggregated T1 Service".

1407. Rio Tinto notes that most of the proposed changes to clause 17.9 are consequential upon the proposed removal of aggregation, and will presumably be preserved if short-term relocation is retained. Rio Tinto considers that the removal of short-term relocation (aggregation), which allows a shipper to relocate capacity in the short term at a point where it does not have contracted capacity (provided it makes an equivalent reduction in its nominations elsewhere to not exceed its contracted capacity in aggregate) is a significant change. Rio Tinto submits that "aggregation" is a very important risk mitigant right for shippers.

523 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4). A public version of this submission is available at: www.erawa.com.au

1408. In response to Rio Tinto's submission, DBP reiterates that the proposed R1 Service is not a T1 Service and refers to the information contained in its supporting submission (#3) on pipeline services.[524] In response to Rio Tinto's comments about the removal of short-term relocation (aggregation), DBP makes reference to its response to clauses 5.5 ("No liability for refusal to Receive gas"), 5.9 ("No change to Contracted Capacity"), 8.15 ("Default provision for Renomination process") and 8.16 ("Shipper's Advanced Nomination").

1409. The Authority has given separate consideration to DBP's proposed changes to clause 5 and 8 at paragraphs earlier in this draft decision. Consistent with these considerations, and the Authority's decision to require the R1 Service to be replaced with the T1 Service, the Authority is of the view that the terms of clause 17.9 relating to aggregation should be reinstated.

Required Amendment 73

Clause 17.9 of the proposed revised terms and conditions, in relation to priority of curtailment, should be amended to be substantially the same as clause 17.9 of the existing terms and conditions.

Clause 17.10 – Apportionment of shipper's curtailments

1410. Clause 17.10 of the proposed terms and conditions set out terms relating to the apportionment of shipper's curtailments. DBP proposes several changes to this clause, indicating that the changes are for reason of what works in practice. The proposed changes are to:

- indicate that the operator may (as opposed to must), in its discretion acting reasonably, apportion any: refusals to deliver gas; or refusals to receive gas; or curtailment of the shipper's contracted capacity service (proposed clause 17.10(a));
- remove terms that specify circumstances where the operator is not required to make the apportionment referred to in clause 17.10(a) (clause 17.10(b) of the 2005 to 2010 terms and conditions); and
- include new terms that specify requirements for circumstances where no apportionment mechanism has been proposed by the shipper and it becomes necessary to effect an apportionment (proposed clause 17.10(e)).

1411. Alinta and Verve Energy each comment on DBP's proposed changes to clause 17.10 and submit that:

- in relation to clause 17.10(a), the apportionments should be made as determined by the shipper, unless standing requirements for an apportionment mechanism under proposed clause 17.10(b) have been proposed by the shipper; and
- the suggested amendments to clause 17.10(a) make clause 17.10(e) redundant. Hence, clause 17.10(e) should be deleted.

524 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4). A public version of this submission is available at: www.erawa.com.au

1412. Rio Tinto submits that the former requirements were stricter on DBP and thus gave the shipper greater operational control in managing the challenges arising from a curtailment. For Rio Tinto to respond efficiently and effectively to a curtailment it must be able to manage how any available gas is directed. Rio Tinto is the view that the proposed changes to clause 17.10 leaves this to DBP's unguided reasonable discretion. Rio Tinto suggests that, as a compromise, and in recognition that clause 17.10 may be administratively burdensome for DBP, the requirements of proposed clause 17.10(b)[525] should be made bilateral, so that the DBP can approach shippers about their curtailment priorities in advance.

1413. In its response to third party submissions, DBP:

- reiterates that the proposed R1 Service is not a T1 Service and makes reference to the information contained in its supporting submission (#3) on pipeline services; and[526]
- submits that, in circumstances of curtailment or refusal to deliver gas, a shipper will have no incentive to cooperate with DBP, as DBP has encountered in the past. Furthermore, DBP needs to have operational control to minimise impacts that result from shipper overruns (i.e. the impact could be worse at particular outlet points).

1414. Having regard to the matters raised by interested parties, including DBP, the Authority is of the view that given its decision to require the R1 Service to be replaced with the T1 Service, clause 17.10 of the proposed revised terms and conditions should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions and to address concerns raised by shippers, also include an additional requirement for DBP to notify the shipper of apportionment as soon as practicable after end of relevant gas day.

1415. The Authority is of the view that the existing clause 17.10(b) enables DBP to act if a shipper does not co-operate. On this basis, and in light of the Authority's decision to replace the R1 Service with a T1 Service, the Authority rejects the proposed changes. Further, although partly repetitive of clause 17.10(a), the Authority is of the view that clause 17.10(e) contains an additional requirement for DBP to notify a shipper of apportionment as soon as practicable after end of relevant gas day which appears to be reasonable and in the interests of shippers.

Required Amendment 74

Clause 17.10 of the proposed revised terms and conditions, in relation to the apportionment of a shipper's curtailments should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions and an additional requirement for DBP to notify the shipper of apportionment as soon as practicable after the end of the relevant gas day be included.

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525 Previously clause 18(c) of the existing 2005 to 2010 terms and conditions for the T1 Service.

526 DBP, 14 April 2010, Confidential supporting submission 3: Pipeline services (section 4). A public version of this submission is available at: www.erawa.com.au

Maintenance and major works (clause 18)

1416. Clause 18 of the proposed revised terms and conditions establishes terms for the notification of maintenance and major works under the contract. DBP proposes several changes to this clause, which are for practical reasons. The changes include:

- the removal of terms that require the operator to notify the shipper of changes to its schedule of major works and planned maintenance issued to shippers under clause 18(c) of the terms and conditions (clause 18(e) of the 2005 to 2010 terms and conditions); and
- the inclusion of additional terms to proposed clause 18(e)[527] to indicate that, where the operator endeavours to give the shipper notice of any material departure from the "annual DBNGP maintenance schedule" that is likely to affect the shipper, the operator will not be bound by any notification it provides.

1417. Alinta and Verve Energy each submit that:

- under clause 18(d), at the shipper's request, the operator must provide the shipper with its estimate of the curtailment to capacity available to the shipper on each day of the planned outages specified in the annual DBNGP maintenance schedule. Any information provided by the operator following a request under clause 18(d) should not limit the operator's obligation to give an initial notice within the timeframes required by clause 17.6(b)(i)(A) ("Curtailment Notice"). This should be clarified.
- under clause 18(g)[528], the operator may, despite clause 18(b) but subject to clauses 18(e) ad 18(f), determine the timing and extent of any curtailment necessitated by major works in its discretion. Curtailment for major works should also be subject to clause 17.6(b)(i)(A) ("Curtailment Notice") and the obligation to give an initial notice not less than 60 days in advance of the curtailment.

1418. In response to third party submissions, DBP submit that:

- No limit is imposed on the operator's obligation to issue an initial notice in circumstances where the operator has provided information under clause 18(d). No clarification is therefore required.
- Curtailment for major works is subject to clause 17.6(b)(i)(A). It does not need to be stated as such in clause 18(g) for the obligation to be effective.

1419. Having regard to the matters raised above, the Authority agrees with DBP that provision of information under clause 18(d) does not limit the obligations of the operator under clause 17.6(b)(i)(A). However, the Authority agrees with Alinta and Verve Energy that in the interests of transparency clause 18(g) should be expressed as being subject to clause 17.6(b)(i)(A).

527 Previously clause 18(f) of the existing 2005 to 2010 terms and conditions for the T1 Service.

528 Previously clause 18(h) of the existing 2005 to 2010 terms and conditions for the T1 Service.

Required Amendment 75

Clause 18 of the proposed revised terms and conditions, in relation to maintenance and major works should be amended as follows.

- Clause 18(d) should be amended to insert "17.6(b)(i)(A)" after "clauses".
- Clause 18 should be amended to include terms that are substantially the same as clause 18(e) of the 2005 to 2010 terms and conditions for the T1 Service, requiring the operator to notify the shipper of changes to its schedule of major works and planned maintenance issued to shippers under clause 18(c) of the terms and conditions.

Force majeure (clause 19)

1420. Clause 19 of the proposed revised terms and conditions establish terms for force majeure under the contract. Clause 19 is materially the same as clause 19 of the 2005 to 2010 terms and conditions for the T1 Service. DBP has, however, proposed changes to the definition of "force majeure" under clause 1 ("Interpretation") of the proposed terms and conditions.

1421. The Authority has considered DBP's proposed changes to the definition of force majeure at paragraph 1010 and following of this draft decision. Subject to these considerations, the Authority is satisfied that the changes to clause 19 of the proposed revised terms and conditions are administrative in nature.

Charges (clause 20)

1422. Clause 20 of the proposed revised terms and conditions establishes terms relating to charges. In addition to changes of an administrative nature to improve drafting expressions, DBP proposes further changes to clauses 20.4, 20.5 and 20.7 that it submits are to be in recognition of the type of service that is the R1 Service.

Clause 20.4 – Other charges

1423. Clause 20.4(a) of the proposed terms and conditions sets out terms relating to charges other than the capacity reservation charge and commodity charge. These "other charges" comprise:

- the excess imbalance charge (proposed clause 9.5);
- the hourly peaking charge (proposed clause 10.3);
- the overrun charge (proposed clause 11.1(a));
- the unavailable overrun charge (proposed clause 11.6 and clause 17.8(e)); and
- any other charges or sums payable under (proposed) clauses 5.10(c), 6.6, 9.9(c)(i), 14.7 and 15.11 or elsewhere in the contract.

1424. Under clause 20.4(b):

> The Parties agree that the Other Charges are genuine pre-estimates of the unavoidable additional costs, losses and damages that the Operator will incur as a result of the conduct entitling such charges to be levied. The Shipper will not be entitled to claim or argue (in any proceeding or otherwise), that any Other Charge is not a genuine pre-estimate of loss or damage that may be incurred by the Operator or is otherwise a penalty or constitutes penal damages.

1425. BHP Billiton submits that the operator should only be able to retain an amount of revenue from the other charges that is equal to the costs the operator incurs as a result of the conduct which entitles such a charge to be levied. The remainder of the revenue from the other charges should be redistributed to the non-offending shippers. BHP Billiton is of the opinion that if this is not done, the operator will make a profit over and above the regulated return; and to do so would be contrary to the national gas objective.

1426. Furthermore, BHP Billiton submits that its submission is consistent with the Authority's decision on the proposed revisions to the access arrangement for the Goldfields Gas Pipeline, in which the Authority noted that it was not reasonable for the service provider to delete the rebate mechanism and thereby retain all the quantity variation charges if this revenue was not taken into account when determining the reference tariff.

1427. Alinta and Verve Energy each submit that clause 20.4(b) should be deleted and refer to other comments made in their respective submissions in relation to the excess imbalance charge, hourly peaking charge and overrun rate charges.

1428. In its response to third party submissions, DBP refers to its comments provided in relation to the other charges.

1429. The Authority has considered the nature of the other charges detailed in clause 20.4(a) of the proposed revised terms and conditions elsewhere in this draft decision. The Authority considers the concerns raised by BHP Billiton, Alinta and Verve are real. However, the Authority notes that clause 20.4(b) is contained in the SSC and accepts that it represents a reasonable balance of the interests of the service provider and users.

1430. The Authority is of the view that given its decision to require the R1 Service to be replaced with the T1 Service, clause 20.4 of the proposed revised terms and conditions should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions. The Authority is also of the view that all of the charges listed above on clause 20.4 should be rebateable to shippers.

Required Amendment 76

Clause 20.4 of the proposed revised terms and conditions, in relation to other charges, should be amended to be substantially consistent with clause 17.10 of the existing terms and conditions and to include a provision for all of the other charges to be rebateable to shippers.

Clause 20.5 – Adjustment to R1 tariff

1431. Clause 20.5 of the proposed terms and conditions sets out the circumstances under which the tariff for the proposed R1 Service can be adjusted under the contract.

> 20.5 Adjustment to R1 Tariff
>
> (a) The Parties acknowledge that:
>
> (i) as at the commencement of this Contract, the R1 Tariff has been calculated in the manner set out in section 3 of the Access Arrangement, as adjusted by the Reference Tariff Variation Mechanism; and
>
> (ii) any adjustment of the R1 Tariff during the term of this Contract will be in accordance with the Reference Tariff Variation Mechanism.

1432. Rio Tinto submits that the proposed tariff escalation mechanism (for the R1 Service) is commercially unattractive as it exposes a shipper to the regulatory risk of having its tariff reset every five years. Rio Tinto is of the view that such a mechanism is inefficient and inconsistent with common practice in shipper contracts to date, which has been to strike a price and escalation path at the start of the contract so that both parties have a predictable and 'bankable' tariff path. Rio Tinto submits that this would be a preferable approach.

1433. In response to Rio Tinto's submission, DBP submits that:

- While it may be the case that the escalation mechanism is commercially unattractive, the mechanism is consistent with the requirements of a regulatory regime. The regulatory regime provides for tariff redetermination at periodic intervals to ensure, among other things, that tariffs do not diverge far from costs.
- DBP has no right and the Authority no power to consider fixing this aspect of the access arrangement in the manner proposed by Rio Tinto.
- DBP further submits that if Rio Tinto saw commercial benefit in a different scheme, whereby a fixed base tariff was escalated following a pre-determined price path over a period longer than the period between access arrangement reviews, it could approach DBP for a non-reference service.

1434. The Authority notes that rule 92 of the NGR provides that a full access arrangement must include a mechanism for variation of a reference tariff over the course of an access arrangement period.

1435. Consistent with the Authority's decision to require amendments to the proposed revised access arrangement to remove the R1 Service as a reference service and to include a full haul T1 Service, the Authority has determined an associated reference tariff for the T1 Service. The Authority has also considered the reference tariff variation mechanism that will apply under the revised access arrangement.

1436. Having regard to the above considerations, the Authority is of the view that Clause 20.5 of the proposed revised terms and conditions should be amended to be consistent with the structure of the reference tariff and reference tariff variation mechanism of the proposed revised access arrangement as required to be amended under this draft decision.

Required Amendment 77

Clause 20.5 of the proposed revised terms and conditions should be amended to be consistent with the structure of the reference tariff and reference tariff variation mechanism of the proposed revised access arrangement as required to be amended under this draft decision.

Other taxes (clause 20.7 of the 2005 to 2010 terms and conditions)

1437. DBP proposes to remove terms and conditions relating to the recovery of amounts that result from changes in taxes (clause 20.7 of the 2005 to 2010 terms and conditions). DBP submits that this change is in recognition of the type of service that is the R1 Service and submits that "additional changes in government charges should be recovered from shippers".[529]

20.7 Other Taxes

If at any time during the Term:

(a) any Tax which was not in force as at the commencement of the Access Arrangement Period is validly imposed;

(b) the rate at which a Tax is levied is validly varied from the rate prevailing as at the commencement of the Access Arrangement Period; or

(c) the basis on which a Tax is levied or calculated is validly varied from the basis on which it is levied or calculated as at the commencement of the Access Arrangement Period,

(called the Tax Change) then, to the extent that the Tax Change changes any costs incurred by Operator in performing its obligations under this Contract or otherwise affects the amounts payable under this Contract, Shipper must pay to Operator an amount equal to the increase in costs attributable to the Tax Change, or Operator must pay to Shipper an amount equal to the decrease in costs attributed to the Tax Change (as the case may be), which amount shall be added to amounts, or deducted from (as the case may be) otherwise due under this Contract.

1438. No interested parties commented on these proposed changes.

1439. Consistent with the Authority's decision to require amendments to the proposed revised access arrangement to remove the R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that clause 20.7 of the existing terms and conditions should be reinstated.

529 DBP, 14 April 2010, Submission number #5: Terms and conditions comparison.

Required Amendment 78

Clause 20.7 of the existing terms and conditions, in relation to other taxes, should be reinstated into the proposed terms and conditions.

Invoicing and payment (clause 21)

1440. Clause 21 of the proposed revised terms and conditions sets out terms for invoicing and payment. DBP proposes several changes to these terms that are in the nature of changes to drafting expressions or changes in response to practical experience. The Authority accepts for the reasons set out below, that the proposed changes to clause 21 are reasonable.

Clause 21.1 – Monthly payment of capacity reservation charge; and Clause 21.2 – Monthly invoicing

1441. Clause 21.1 sets out terms for monthly payment of the capacity reservation charge. DBP proposes changes to these terms to make it explicit that the tax invoice, provided by the operator to the shipper in respect of the capacity reservation charges payable for the month, must separately show the capacity reservation charges for each capacity service.

1442. DBP proposes similar changes to clause 21.2, which details the terms for monthly invoicing. The changes make it an explicit requirement that the tax invoice to show for each capacity service:

- the quantity of gas delivered by the shipper at each inlet point and the quantity of gas delivered by the operator at each outlet point on each gas day in the month;
- the commodity charges for the month; and
- all other charges payable for the month.

1443. No interested parties commented on these proposed changes.

1444. The Authority is satisfied that the proposed changes to clauses 21.1 and 21.2 are likely to be reflective of practical experience, as submitted by DBP. Taking this into consideration, and in the absence of any submissions from interested parties, the Authority considers that the proposed changes serve to clarify that tax invoices should, where applicable, show invoice and payment data for each capacity service.

Clause 21.4 – Default in payment; and Clause 21.6 – Correction of payment errors

1445. Clause 21.4 establishes terms for the payment of interest where the shipper or operator defaults in the payment of any charges or rebates. Clause 21.6 establishes terms for the payment of interest where a payment error (underpayment or overpayment) occurs. DBP proposes changes to these terms to make the calculation of the interest payable subject to compounding.

1446. Alinta and Verve Energy each submit that interest on unpaid amounts (under clause 21.4) and interest on incorrect amounts (under clause 21.6) should not be compounded.

1447. In response to these third party submissions, DBP submits that the clauses should remain as proposed.

1448. In the absence of any detailed reasoning from DBP, the Authority does not agree that the interest should be compounded for a default of payment or a correction of payment errors.

Required Amendment 79

Clauses 21.4 and 21.6 of the proposed revised terms and conditions should be amended to remove the words "and compounded" in relation to the interest payable for a default in payment or correction of payment errors by a shipper.

Default and termination (clause 22)

1449. Clause 22 of the proposed revised terms and conditions sets out default and termination provisions. DBP proposes various changes to this clause that it submits are of an administrative nature or in light of practical experience.

Clauses 22.1 – Default by shipper

1450. Clause 22.1 sets out the circumstances where the shipper is considered to be in default under the contract. DBP proposes changes to clauses 22.1(a) and (c) to clarify the default positions of the shipper.

The Shipper is in default under this Contract only if:

(a) the Shipper defaults in the due and punctual payment, at the time and in the manner prescribed for payment by this Contract, of any amount payable under this Contract<u>. For the avoidance of doubt, withholding of a disputed amount in accordance with clause 21.5 is not considered a default</u>;

…

(c) without the Operator's prior consent, the Shipper sells, parts with Possession of or attempts to sell or part with Possession of, the whole or a substantial part of its undertaking<u>, so far as that undertaking relates to the use of Gas Delivered under this Contract</u>; …

1451. No interested parties commented on these proposed changes.

1452. The Authority is satisfied that DBP's proposed changes to clause 22.1 are likely to be reflective of practical experience and considers that the changes serve to clarify when a shipper is in default under the contract.

Clause 22.2 – Notice of shipper's default; and Clause 22.6 – Notice of operator's default

1453. Clause 22.2 establishes how the operator is to notify the shipper of a default ("shipper default notice"). Similarly, clause 22.6 establishes how the shipper is to notify the operator of a default ("operator default notice"). DBP proposes changes to these clauses to remove the requirement for the respective default notices to be in writing by certified mail. DBP submits that these changes are for reason of what works in practice.

1454. Alinta and Verve Energy both submit that, given the importance of default notices, the requirement to give such notices by certified mail should be reinstated.

1455. In response to these third party submissions, DBP submits that if the issue is important the default notice needs to be sent immediately. DBP further submits that it could consider a requirement for the default notice to be couriered.

1456. The Authority notes that while DBP has proposed changes to clauses 22.2 and 22.6 to remove the requirement for default notices to be sent by certified mail, DBP has retained the requirement for the notices to be made in writing. The Authority considers this requirement to be the primary requirement for default notices and acknowledges that, for reasons of importance, timeliness and practicality, alternative transmittal options to that of certified mail may be warranted. In light of this, the Authority is satisfied that the proposed changes do not materially affect the form of the default notice and enables parties to determine the most appropriate means of transmittal.

Clause 22.3 – When the operator may exercise remedy

1457. DBP submits that the proposed changes to clause 22.3, in relation to when the operator may exercise a remedy, are for administrative reasons and are mostly minor grammatical changes. However, the Authority notes that DBP has changed a period of time in clause 22.3(b)(ii) from 40 working days to 20 working days. This change makes the clause inconsistent with clause 22.7(b)(i).in relation to when a shipper may exercise a remedy. Given that the aforementioned clauses essentially establish the same provisions, the Authority is of the view that in the absence of any evidence to the contrary, the time period for a DBP or shipper to exercise a remedy should be consistent.

Required Amendment 80

Clause 22.3 of the proposed revised terms and conditions, in relation when the operator may exercise a remedy, should be amended to replace the reference to "20 Working Days" with a reference to "40 Working Days".

Clause 22.9 – No indirect damages

1458. DBP proposes to add a new clause 22.9 ("No Indirect Damages") to the proposed revised terms and conditions. DBP submits that this change is for reason of what works in practice.

22.9 No Indirect Damages

The right of termination (with the right to recover Direct Damages) under the preceding clauses are the Shipper's sole and exclusive remedy in respect of a repudiation or disclaimer and the Operator (despite any provision of clause 23) is not liable to the Shipper for any other Indirect Damage arising in respect of a repudiation or disclaimer.

1459. Rio Tinto assumes that the exclusion of indirect damages, which it considers to be superfluous, should be subject to clause 23.2 ("Liability for fraud") and other liabilities incurred before the repudiation or disclaimer.

1460. Alinta and Verve Energy each submit that the proposed addition is unsatisfactory and should be deleted. These parties further submit that clause 23.2, which sets out liability provisions for fraud, should be amended to include references to "wilful defaults".

1461. In its response to third party submissions, DBP submits that it is commercially unreasonable, and in the operator's experience most unusual, to expect a party to contract such as to accept liability for "consequential" loss. Such liabilities are not insurable.

1462. The Authority has considered submissions, including DBP's, and considers that the addition of clause 22.9 is not reasonable as clauses 23.2 and 23.3(c) already provide an indemnity in favour of DBP against a claim for Indirect Damage save in circumstances of fraud. The Authority is of the view that there is no reasonable justification for extending the indemnity against Indirect Damage in circumstances where fraud exists in relation to a repudiation or disclaimer of the contract by the Operator. On the other hand, the Authority is equally unconvinced that it is commercially reasonable to require DBP to extend the operation of clause 23.2 to circumstances of wilful default.

Required Amendment 81

Clause 22.9 of the proposed revised terms and conditions, in relation to no indirect damages, should be deleted.

Liability (clause 23)

1463. Clause 23 of the proposed revised terms and conditions establishes terms for liability. In particular, clauses 23.6 and 23.7 establish the shipper's and operator's responsibility for contractors' personnel and property respectively. DBP proposes changes to these clauses to remove the exception to liability for injury or death to a party's personnel, or loss or damage to a party's property; the exception being to the extent the liability was contributed to by an act or omission of the other party. DBP submits that these changes are for reason of what works in practice.

1464. Both Alinta and Verve Energy submit that the exception to liability for death or injury to a party's personnel or damage to a party's property is an appropriate allocation of liability and should be reinstated.

1465. In its response to third party submissions, DBP submits that a 'knock-for-knock' insurance regime is more efficient than a fault-based regime. Furthermore, knock-for-knock insurance is commonplace in the oil and gas industry.

1466. The Authority has considered submissions and considers that it has insufficient information to assess whether the proposed change to the allocation of risk is appropriate on the basis that 'knock for knock' insurance regime is more efficient than a fault-based regime. In the circumstances, the Authority is of the view that the exception to liability for death or injury to a party's personnel or damage to a party's property is a fair and appropriate allocation of liability and should be reinstated.

Required Amendment 82

Clauses 23.6 and 23.7 of the proposed revised terms and conditions, which establish the shipper's and operator's responsibility for contractors' personnel and property respectively, should be amended to reinstate the liability for death or injury to a party's personnel or damage to a party's property.

Assignment (clause 25)

1467. Clause 25 of the proposed terms and conditions establishes terms relating to the assignment of rights, interests or obligations under the contract. DBP proposes various changes to clause 25 and submits that these changes are for reasons of changes in drafting expression, practical experience and/or in recognition of the type of service that is the R1 Service.

Clause 25.1 – No assignment except under this clause

1468. Alinta and Verve Energy both question the intent of clause 25.1, which states:

> Subject to this clause 25 and to clause 27, neither Party may assign any right, interest or obligation under this Contract (but this clause 25 does not prevent the creation of an interest for the Shipper. *[sic]*

1469. Alinta and Verve Energy suggest that this clause should be amended to read: "(but this clause 25 does not prevent the Shipper from creating equitable or other interests in relation to its rights under the Contract)".

1470. In its response to third party submissions of Alinta and Verve Energy, DBP submits that the words "but this clause 25 does not prevent the creation of an interest for the shipper" have been included in error and should be deleted.

1471. Given DBP's submission, the Authority requires clause 25.1 of the proposed terms and conditions to be amended accordingly.

Required Amendment 83

Clause 25.1 should be amended to read: *"Subject to this clause 25 and clause 27, neither Party may assign any right, interest or obligation under this Contract"*.

Clause 25.2 – Charges

1472. Clause 25.2 of the proposed revised access arrangement establishes terms for a tripartite deed to allow a party to charge in favour of any recognised bank or financial institution or a related body corporate of the party the whole or any part of its rights or interests under the contract. Proposed changes to this clause remove reference to the tripartite agreement in Schedule 7 of the 2005 to 2010 terms and conditions and include reference to a tripartite deed that is published on the operator's website from time-to-time. DBP submits that this change is for practical reasons.

1473. Several parties commented on the proposed change to clause 25.2.

- Alinta and Verve Energy both submit that the form of tripartite should be appended to the contract itself.
- BHP Billiton submits that the broad effect of this change has made it harder for shippers to grant security, by requiring the tripartite deed to be in a form which is published on the operator's website (rather than a form approved by the regulator in the terms and conditions), therefore giving the operator unilateral discretion as to the terms of the tripartite deed.
- Rio Tinto submits that it is unrealistic and inefficient to expect parties to sign a tripartite deed which is determined solely in DBP's discretion. The form of tripartite agreement should be settled and appended to the contract.

1474. In response to these third party submissions, DBP submits that reference to the tripartite deed on the operator's website provides greater flexibility; enabling changes and updates to be made to the deed as required and appropriate, and independent of the terms and conditions. DBP further submits that it is not in the operator's interest to make it harder for shippers to grant security. DBP does not follow how terms of a tripartite deed on the operator's website are to be any more onerous than those which would have otherwise been approved by the regulator.

1475. Having regard to these matters, the Authority is of the view that it is reasonable for the terms and conditions to include the tripartite deed and that it should continue to form part of the terms and conditions.

Required Amendment 84

Clause 25.2(a) should be amended to include terms that are substantially the same as clause 25.2(a) of the 2005 to 2010 terms and conditions for the T1 Service, requiring the form of tripartite deed to be annexed in a schedule to the terms and conditions.

25.3 – Assignment

1476. Clause 25.3 of the proposed revised terms and conditions establishes terms for a party to assign all or part of its rights and interests under the contract. DBP proposes changes to this clause for reasons of practical experience. In particular, DBP proposes to change the criteria whereby a party may assign its rights or interests without obtaining the consent of the other party where the assignment is to a related corporate body (clause 25.3(a)).

(a) A Party may assign all or part of its rights and interests under this Contract without obtaining the consent of the other Party where that assignment is to a Related Body Corporate provided that:

(i) where the assignor is the Shipper, such assignment does not release the assignor from liability;

(ii) where the assignor is the Operator, such assignment does not release the assignor prior to the assignment date;

(iii) where the assignor is the Shipper, if the Operator reasonably considers that the proposed assignee is not likely to meet the Shipper's obligations under this Contract, the proposed assignee provides, or undertakes to provide security for those obligations on terms and conditions acceptable to the Operator; and

(iv) upon the assignee ceasing to be a Related Body Corporate of the assignor, the assignee must immediately transfer all of its rights and interests, under this Contract to the assignor.

1477. In addition, DBP proposes changes to clause 25.3(d) which details the circumstances where the shipper may withhold its consent to an assignment of the operator's obligations under the contract. DBP proposes to remove explicit references to contractual or ownership rights to access the DBNGP, and financial capability and technical expertise to enable the assignee to effectively operate the DBNGP (clauses 25.3(d)(i) and (ii) of the 2005 to 2010 terms and conditions respectively) as valid circumstances. These explicit circumstances have been replaced with a broader reference to "the necessary contractual, statutory or ownership rights for the purposes of performing all of the Operator's obligations under [the] Contract".

1478. Alinta, Verve Energy, BHP Billiton and Rio Tinto all comment on DBP's proposed changes to clause 25.3.

- Alinta and Verve Energy each submit that there is no reason for the treatment of liability, following assignment, to be different between the shipper and the operator. If the operator, as assignor, is to be released from liability it must be by way of a formal deed of assumption or novation, which the shipper has approved or is party to; this is consistent with the operation of clause 25.4(a) ("Assignment: deed of assumption").

- BHP Billiton submits that the proposed changes: increase the difficulty of assignment by shippers to related bodies corporate by requiring the proposed assignee to provide security; have changed the previously reciprocal nature of the clause by allow the operator to be released from future liability (but not the shipper); and remove the shipper's ability to withhold consent to an assignment by the operator on the bases of financial capability and technical expertise. BHP Billiton submits these changes are unreasonable; going beyond changes required to accommodate legislative requirements and changes that would be accepted in a competitive market.
- Rio Tinto is of the opinion that the terms of clause 25.3 are more detailed and one-sided, and objects to the unilateral shift in DBP's favour. Rio Tinto submits that the proposed changes to clause 25.3(a) should be deleted and that the proposed removal of clause 25.3(d)(ii) is difficult to justify. A shipper has a clear interest in ensuring that DBP's proposed assignee has adequate funds and expertise; removal of these terms risks an assignment to an inadequately resourced operator.

1479. DBP disagrees with the above submissions. In its response to third party submissions, DBP submits that it is quite usual for the owner of an asset, of this kind and scale used, to provide a service with the right to deal with that asset on a reasonable basis, without individual customers having the right to veto the transaction. On the other hand, the owner of the asset is critically dependent on the creditworthiness of its customers and requires the right to vet the creditworthiness of its counterparts.

1480. The Authority accepts the concerns raised by shippers and considers that the proposed changes are not consistent with the national gas objective.

Required Amendment 85

Clause 25.3 of the proposed revised terms and conditions, in relation to assignment, should be amended to be substantially the same as the existing terms and conditions.

Clause 25.4 – Assignment: deed of assumption

1481. Clause 25.4 of the proposed revised terms and conditions establishes terms for the assignment of rights and interests. DBP proposes to add new terms to this clause for reason of what works in practice. The additional terms are included in proposed clauses 25.4(b) and 25.4(c).

(b) The Shipper must not assign all or part of its rights and interest under this Contract unless:

(i) the Operator is satisfied that the proposed assignee is likely to meet the Shipper's obligations under this Contract; or

(ii) the proposed assignee provides, or undertakes to provide security for those obligations on terms and conditions acceptable to the Operator.

(c) The Operator must not assign all or part of its rights and interest under this Contract, or title or interest in the DBNGP without requiring the assignee to enter into a deed of assumption with the Shipper under which it:

(i) assumes all, or the relevant portion, of the Pipeline Trustee's obligations under this Contract in respect of the Shipper (and the Shipper agrees that the Pipeline Trustee is released to the extent that the Pipeline Trustee's obligations are assumed); and

(ii) acknowledges that its obligations under such assumption of obligations extend to the Operator's obligations under the Relevant Agreements.

1482. BHP Billiton submits that the addition of clause 25.4(b) is inappropriate from a drafting perspective as it is unclear how this clause interacts with clause 25.3(c), given that both clauses appear to cover the same ground in relation to the operator's ability to withhold consent.

1483. Rio Tinto submits that if changes are to be made to clause 25.4, the changes should be bilateral. Clause 25.4(b)(ii) should detail the form of security to be given, by both parties' assignees, and append the necessary instrument. Rio Tinto further suggests that a common approach would be for security in the form agreed by the parties acting reasonably, but failing agreement a bank undertaking or parent company guarantee in the scheduled form.

1484. The Authority agrees that it is reasonable that any proposed changes to clause 25.4 should apply equally under clause 25.3 and therefore is of the view that clause 25.4 should be substantially consistent with the existing terms and conditions.

Required Amendment 86

Clause 25.4 of the proposed revised terms and conditions, in relation to a deed of assumption, should be amended to be substantially consistent with the existing terms and conditions.

Clause 25.5 – Pipeline Trustee's acknowledgement and undertakings; and DBNGP Trustee's acknowledgement and undertakings (clause 25.6 of the 2005 to 2010 terms and conditions)

1485. Clause 25.5 of the proposed revised terms and conditions detail the pipeline trustee's acknowledgements and undertakings. DBP proposes changes to this clause that vary the pipeline trustee's acknowledgements and undertakings from those detailed in the 2005 to 2010 terms and conditions, and to remove the acknowledgments and undertakings of the DBNGP Trustee (clause 25.6 of the 2005 to 2010 terms and conditions). DBP submits that these changes are for reason of what works in practice and/or in recognition of the type of service that is the R1 Service.

1486. DBP notes that the changes made in relation to clause 25.5 are the deletion of paragraphs (e) - (g) relating to entering a into an assignment/assumption deed if the Pipeline Trustee disposes of its interest in the DBNGP. However, DBP submits that there has been no change to the acknowledgment and undertakings that the Pipeline Trustee is providing in this regard because the obligations relating to entering into a deed for the disposal/assignment of the DBNGP have been relocated to clause 25.4(c). DBP also submits that the reason that the DBNGP Trustee's acknowledgements have been deleted is that the DBNGP Trustee is not a party to the R1 Contract.[530]

1487. No submissions to the Authority addressed these proposed changes.

1488. Consistent with the Authority's decision to require amendments to the proposed revised access arrangement to remove the R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that clause 25.5 should be substantially the same as clause 25.5 of the existing terms and conditions. Similarly, clause 25.6 of the existing terms and conditions should be maintained in the proposed revised terms and conditions.

Required Amendment 87

Clause 25 the proposed revised terms and conditions should be amended to include terms and conditions that are substantially the same as clauses 25.5 and 25.6 of the existing terms and conditions for the T1 Service, which set out the acknowledgements and undertakings of the Pipeline Trustee and DBNGP Trustee respectively.

Non-complying assignment (clause 25.7 of the 2005 to 2010 terms and conditions)

1489. DBP has proposed to remove terms relating to non-complying assignment (clause 25.7 of the 2005 to 2010 terms and conditions). This clause provided that any purported sale, transfer or assignment that was in breach of the requirements of any of the provisions of this clause 25 was not legally binding. DBP submits that this change is for reason of what works in practice.

1490. The Authority does not object to the deletion of clause 25.7 of the existing terms and conditions.

530 DBP, 8 December 2010, Submission 36: Response to ERA Information Request 17 November 2010, Confidential.

Clause 25.6 – Utilising other shipper's daily nominations

1491. Clause 25.6 of the proposed revised terms and conditions establish terms for the shipper to utilise other shippers' daily nominations. DBP proposes changes to these terms to make the shipper's agreement to utilise its daily nominations on behalf of another shipper, or another shipper agreeing to utilise its daily nominations on the behalf of the shipper, subject to the shipper entering into an inlet sales agreement. DBP submits that this change is for reason of what works in practice.

1492. Alinta and Verve Energy each submit that the terms of clause 25.6 should be reinstated as previously drafted, otherwise these terms are a further devaluation of the R1 Service from the T1 services, which must be reflected in a lower R1 tariff.

1493. BHP Billiton submits that the amendment, to impose a requirement on shippers to enter into an inlet sales agreement before they can utilise other shippers' daily nominations, is unjustifiable; particularly where DBP retains the flexibility to determine the terms of that arrangement from time-to-time. This reduces competition and efficiency as the arrangement could be used to effectively prevent the utilisation of capacity for third parties.

1494. In its response to third party submissions, DBP submits that the proposed reference service (R1 Service) is not a T1 Service and does not provide all the rights of a T1 Service. DBP also submits that a shipper needs to be able to warrant that it has custody and title to the gas at the inlet point; this is achievable by an inlet sales agreement.

1495. Having regard to the competition and efficiency issues and the matters raised by interested parties, including DBP, and the Authority's decision to remove the R1 Service and retain the T1 Service, the Authority is of the view that the proposed amendments should not be allowed.

Required Amendment 88

Clause 25.6 of the proposed revised terms and conditions should be amended to include terms and conditions substantially the same as clause 25.6 of the existing terms and conditions.

General right of relinquishment (clause 26)

1496. DBP has proposed to remove, from the proposed revised terms and conditions, the terms for a general right of relinquishment by a shipper (clause 26 of the 2005 to 2010 terms and conditions). DBP submits that this change has been made for reason that the provisions are not appropriate for a R1 Service.

1497. Alinta and Verve Energy both question why the relinquishment provisions have been removed and submit that the provision enabling the shipper to offer to relinquish contracted capacity should be reinstated. Similarly, BHP Billiton disputes the removal of the general right of relinquishment contained in clause 26, submitting that the changes may impact on the ability to effectively utilise unutilised capacity and therefore reduce efficiency.

1498. In its response to third party submissions, DBP submits that the relinquishment provisions (of clause 26 and 27.12) have been removed on the basis that the proposed terms and conditions are for the proposed R1 Service – the R1 Service is not a T1 Service and therefore does not provide all the rights of a T1 service. In addition, DBP submits that shippers already have a right to a shorter term of contract than a T1 contract. Giving shippers a relinquishment right as well as a right to a shorter term contract creates uncertainty for the service provider.

1499. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority believes that the terms for a general right of relinquishment by a shipper (clause 26 of the 2005 to 2010 terms and conditions) should be maintained in the proposed revised terms and conditions particularly as such a right is consistent with the efficient use of the pipeline.

Required Amendment 89

Clause 26 of the proposed revised terms and conditions should be amended to be substantially the same as clause 26 of the 2005 to 2010 terms and conditions for the T1 Service, which establishes terms for a general right of relinquishment by a shipper.

Trading or transferring contract capacity (clause 27)

1500. Clause 27 of the proposed revised terms and conditions establish terms for the trading or transferring of contracted capacity. DBP proposes a number of changes to this clause for reasons of changes in drafting expressions, practical experience, or that the terms are not appropriate for an R1 service. In particular, DBP has proposed the removal of terms for the operator to carry out functions as a broker in the transfer of contracted capacity (clauses 27.11 and 27.12 of the 2005 to 2010 terms and conditions).

Clause 27.1 – No transfer of contracted capacity other than by this clause

1501. Under clause 27.1 of the proposed revised terms and conditions:

- A shipper must not transfer any of its contracted capacity other than in accordance with clause 27 or clause 25 ("Assignment"), as the case may be (proposed clause 27.1(a)).
- Subject to clause 25.6 ("Utilising other shippers' Daily Nominations"), neither clause 27.1(a) nor clause 25.1 ("No assignment except under this clause") prevents the shipper agreeing to utilise its daily nominations either on behalf of another shipper or having another shipper utilise its daily nominations on behalf of the shipper (proposed clause 27.1(b)).

1502. Alinta Sales and Verve Energy both submit that clause 27.1(b) should not be subject to clause 25.6 of the terms and conditions.

1503. In response to these third party submissions, DBP submits that the reference to clause 25.6 should remain because it clarifies that an "Inlet Sales Agreement" is required. The Authority is of the view that clause 27 of the proposed terms and conditions is consistent with the capacity trading requirements of the rules and provisions of the proposed revised access arrangement.

Clause 27.4 – Transfer of capacity by shipper - approval of transfer terms

1504. Clause 27.4 sets out terms for the processing and approval of the transfer of tradable capacity. DBP has proposed changes to clause 27.4(a) to remove terms that allow the shipper to request that the transfer of all or part of its contracted capacity be "for a duration less than or equal to the remaining duration of the period of supply". DBP submits that this change is for practical reasons.

1505. Both Alinta Sales and Verve Energy submit that while DBP has proposed this revision to clause 27.4(a), it is implied from clause 27.4(b) that the request, for a duration less than or equal to the remaining duration of the period of supply, is still an option. If this is the case, the terms and conditions should state this; clause 27.4(a) should not be changed.

1506. In its response to third party submissions, DBP submits that the duration of the transfer is to be negotiated between the shipper and the operator at the time of the request for transfer.

1507. The Authority is of the view that the proposed change to clause 27.4 creates ambiguity and in the interests of clarity it is preferable that the existing wording is retained to expressly state that the transfer may be less than or equal to the remaining period of supply.

Required Amendment 90

Clause 27.4 of the proposed revised terms and conditions, in relation to transfer of capacity, should be amended to be substantially consistent with the existing terms and conditions.

Clause 27.5 – Posting of tradable capacity

1508. DBP has proposed changes to clause 27.5 of the proposed terms and conditions to provide that the operator may (as opposed to must) undertake the obligation to, at the shipper's request:

- notify other shippers, who are or may be interested in taking a transfer of tradable capacity, of details of approved tradable capacity in a way that all shippers receive notice at approximately the same time as when the operator makes available any bulletin dealing with the amount of capacity available for nomination or re-nomination on a gas day (proposed clause 27.5(a)); and
- provide a statement of the current details of all other shippers' approved tradable capacity (proposed clause 27.5(b)).

1509. DBP submits that the proposed changes to clause 27.5 are for reasons of practical experience. No submissions to the Authority commented on these proposed changes and the Authority is satisfied the proposed changes to this clause are reasonable.

Further marketing service; and Relinquishment (clauses 27.11 and 27.12 of the 2005 to 2010 terms and conditions respectively)

1510. DBP proposes to remove terms for the operator to carry out functions in the transfer of contracted capacity:

- The operator may, if requested by the shipper, to the extent that it considers it is prudent to do so, take steps to market as a broker, but not as a buyer and reseller, tradable capacity in ways other than posting (under clause 27.5) (clause 27.11 of the 2005 to 2010 terms and conditions).
- Where under the contract the shipper has given a "relinquishment notice" or a notice indicating that it wishes to relinquish capacity, the operator may request that the shipper instead transfer the relevant capacity to a third party (clause 27.12 of the 2005 to 2010 terms and conditions).

1511. DBP submits that the proposal to remove clause 27.11 is for reason of practical experience, whereas the proposal to remove clause 27.12 is for reason that the clause is not appropriate for a R1 Service.

1512. Alinta Sales and Verve Energy both consider that the provision to provide a further marketing service does not represent an onerous obligation on the operator and therefore clause 27.11 should be reinstated in the proposed terms and conditions.

1513. In its response to third party submissions, DBP submits that it is not appropriate to provide these terms as it is not appropriate for the type of service that is the R1 Service. DBP refers to the reasons set out in its supporting submissions (#3 and #5) for not providing all the rights available under the T1 Service.

1514. The Authority notes that DBP's reasoning for its proposal to remove clause 27.11 varies from the information provided in Supporting Submission #5 (for reason of practical experience) and DBP's response to third party submissions (for reason of not being appropriate for a R1 Service).

1515. The Authority notes that clauses 27.11 and 27.12 only provide a general discretion for DBP to undertake these functions. Accordingly, the Authority is of the view that their removal does not have any substantive adverse effect on shippers.

Confidentiality (clause 28)

1516. Clause 28 of the proposed revised terms and conditions contain terms for the confidentiality of information under the contract. In addition to changes to address drafting expressions, DBP proposes changes to include additional exceptions to the requirements for confidentiality (clause 28.2) and to remove terms that require the operator to procure an independent audit in relation to undertakings to the ACCC (clause 28.10). DBP submits that these other changes are for reason of what works in practice and/or the terms are not appropriate for a R1 Service.

Clause 28.2 – Exceptions to confidentiality

1517. Clause 28.2 of the proposed revised terms and conditions specifies exceptions to the requirements for confidentiality of information. DBP proposes to add two additional exceptions to the terms and conditions where a party may disclose confidential information:

- where the information is requested by an operator of a pipeline which is interconnected with the DBNGP (proposed clause 28.2(j)); and
- where the information is required by law or any governmental agency to be disclosed in connection with any emissions generated by or associated with the operation of the DBNGP proposed (clause 28.2(k)).

1518. Alinta and Verve Energy both submit that the disclosure of confidential information to an operator of an interconnected pipeline, under clause 28.2(j), should be limited to circumstances where the information relates to, and is necessary for, the operation of the interconnected pipeline.

1519. In its response to third party submissions, DBP submits that it agrees that the disclosure of confidential information to an operator of an interconnected pipeline must relate to and be necessary for the operation of the interconnected pipeline. Accordingly, the Authority requires clause 28.2(j) of the proposed terms and conditions to be amended.

1520. While Rio Tinto submits that it supports the intent of the changes to clause 28.2, it submits that clause 28.2(k) is too narrow because it only relates to mandatory disclosure. Rio Tinto suggests that an additional class of permitted disclosure be added to enable parties to "disclose information on a confidential, aggregated or de-identified basis" to other parties, such as customers, to the extent reasonably necessary to assist all parties to comply with their obligations for (carbon) emissions reporting.

1521. In response to Rio Tinto's submission, DBP submits that, as drafted, clause 28.2(k) would entitle a shipper to disclose information in the circumstances identified by Rio Tinto.

1522. Having regard to the submissions from Rio Tinto and DBP on an additional class of permitted disclosure, the Authority considers that the additional class of disclosure is unnecessary as if the confidential information is required by law or a government agency to be disclosed 'in connection with' DBNGP emissions reporting, it will not be a prohibited disclosure.

Required Amendment 91

Clause 28.2 of the proposed revised terms and conditions should be amended as follows:

- Clause 28.2(j) should be amended so that the exception to confidentiality, where the information is requested by an operator of a pipeline which is interconnected with the DBNGP, is subject to the confidential information being relevant to and necessary for the operation of the interconnected pipeline.

Clause 28.3 – Permitted disclosure

1523. Clause 28.3 of the proposed revised terms and conditions set out terms for the permitted disclosure of confidential information to related bodies corporate. Apart from changes to drafting expressions, this clause remains materially unchanged from clause 28.3 of the 2005 to 2010 terms and conditions for the T1 Service.

1524. Clause 28.3(a)(i) specifies that, for the purposes of clause 28.3(a), "Alcoa, WestNet and the System Operator must be considered Related Bodies Corporate of the Operator". In relation to this clause, BHP Billiton notes that Alcoa is currently a shipper on the DBNGP and submits that the operator should be prohibited from disclosing confidential information to a third party shipper who is also an owner on the basis that it is anti-competitive and contrary to the national gas objective.

1525. In its response to third party submissions, DBP submits that the operator is required to comply with ring fencing provisions under the National Gas Law (NGL) and NGR; a prohibition on disclosures not permitted under the law is therefore not required.

1526. The Authority considers that clause 28.3 should be amended to expressly incorporate the operator's obligations to comply with ring fencing provisions under the NGL and NGR.

Required Amendment 92

Clause 28.3 of the proposed revised terms and conditions, in relation to permitted disclosure, should be amended to expressly incorporate the operator's obligations to comply with ring fencing provisions under the NGL and NGR

Audit (clause 28.10 of the 2005 to 2010 terms and conditions)

1527. DBP proposes to remove terms requiring the operator to procure an independent audit in relation to compliance with undertakings to the ACCC under section 87B of the then *Trade Practice Act 1974* (clause 28.10 of the 2005 to 2010 terms and conditions). DBP submits that this is for practical reasons and because the clause is not appropriate for the R1 Service.

1528. Rio Tinto submits that the audit commitment was retained in clause 5.4 of the ACCC undertakings when the undertakings were amended in early 2010 and that shippers have a legitimate interest in seeing that this audit obligation is complied with.

1529. In response to Rio Tinto's submission, DBP submit that clause 28.10 is not required in the terms and conditions as the Undertakings contain the obligation to undertake an audit of compliance with the Undertakings.

1530. The Authority has considered Rio Tinto's submission and DBP's response. The Authority agrees with DBP that the requirement to undertake the audit is an obligation that exists in the ACCC Undertaking. A failure of DBP to meet the obligation should be dealt with according to the undertaking and the provisions of the Australian Consumer Law. To have the obligation reproduced in the terms and conditions does not add to the obligation itself, although it potentially exposes DBP to additional adverse consequences (i.e. remedies for default under the service agreement) if it fails to meet the obligations. As it is difficult to envisage circumstances in which a shipper would enforce the audit undertaking, the Authority accepts the deletion of clause 28.10 of the existing terms and conditions.

Representations and warranties (clause 30)

1531. Clause 30 of the proposed revised terms and conditions establishes certain representations and warranties for the operator, shippers and trustees. In addition to changes to address drafting expressions, DBP proposes changes to remove certain warranties of the operator and trustees to the shipper. DBP submits that these other changes are for reasons of practical experience and/or the terms and conditions are not appropriate for a R1 Service.

Clause 30.1 – Operator's representations and warranties

1532. DBP proposes to remove terms that require the operator to warrant to the shipper that it has duly complied and will continuously comply with all environmental and safety laws with respect to any of its obligations connected with, arising out of, or in relation to, the contract (clause 30.1(a)(i) of the 2005 to 2010 terms and conditions).

1533. Alinta, Verve Energy, BHP Billiton and Rio Tinto all submit that clause 30.1(a)(i) should be retained in the proposed terms and conditions as it is an important warranty to shippers. Rio Tinto notes that it would be odd if DBP is not in a position to give this warranty.

1534. In its response to third party submissions, DBP submits that the operator is required to comply with environmental and safety laws independent of contractual obligations and as such compliance is appropriately managed under those regimes. The operator continues to warrant that it has all necessary approvals under environmental and safety laws in order to meet its obligations under the contract and to allow those obligations to be enforced.

1535. The Authority notes that, apart from clause 30.1(a)(i), DBP has retained all warranties of the operator that are currently offered under the 2005 to 2010 terms and conditions for the T1 Service. In particular, DBP has retained terms that require the operator to warrant to the shipper that:

> it has in full force and effect all authorisations, licences, permits, consents, certificates, authorities and approvals necessary under all Environmental And Safety Laws and all other Laws to enter into this Contract, to observe its obligations under this Contract and to allow those obligations to be enforced;[531]

1536. The Authority considers that it is appropriate that DBP's warranty in clause 30.1(a)(i) with respect of past and continuous compliance with environmental and safety laws be retained and is not satisfied that shippers should be left to rely upon operator's compliance with the regime independently of the contract. In this regard, the Authority notes that the shipper's warranties to the operator contain a similar warranty in proposed clause 30.2(a)(i).

531 Clause 30.1(a)(i) of the proposed revised terms and conditions (previously clause 30.1(a)(ii) of the 2005 to 2010 terms and conditions).

Required Amendment 93

Clause 30.1 of the proposed revised terms and conditions, in relation to operator's representations and warranties, should be amended to be substantially consistent with the existing terms and conditions.

Clause 30.2 – Shipper's representations and warranties

1537. DBP proposes changes to clause 30.2(a)(ii) to narrow the shipper's representations and warranties with respect to environmental and safety laws by removing references to "licences, permits, consents, certificates, authorities and approvals":

(a) Subject to clause 30.2(b), the Shipper represents and warrants to the Operator that:

…(ii) it has in full force and effect all authorisations~~, licences, permits, consents, certificates, authorities and approvals~~ necessary under all Environmental And Safety Laws and all other Laws to enter into this Contract, to observe its obligations under this Contract, and to allow those obligations to be enforced;

1538. While no submissions to the Authority addressed this proposed change, the Authority is of the view that such a change may not promote the efficient investment in, and the efficient operation and use of, natural gas services for the long term interests of consumers as shippers as the source of the shipper's obligations with respect to environmental and safety laws may vary and it is reasonable to require the shipper to warrant compliance with those legal instruments that are relevant to their obligations.

Required Amendment 94

Clause 30.2 of the proposed revised terms and conditions, in relation to operator's representations and warranties, should be amended to be substantially consistent with the existing terms and conditions.

Clause 30.3 – Pipeline Trustee's representations and warranties

1539. DBP proposes changes to clause 30.3 to remove the following warranties of the Pipeline Trustee to the shipper:

- that the Pipeline Trust is registered under s601EB of the *Corporations Act 2001 (Cth)* (clause 30.3(a)(vii) of the 2005 to 2010 terms and conditions); and
- that the Pipeline Trust holds a dealer's licence authorising it to operate the Pipeline Trust (clause 30.3(a)(viii) of the 2005 to 2010 terms and conditions).

1540. DBP submits that this reflects that the Pipeline Trust is not so registered and that it is not required to be registered.[532] The Authority accepts that the removal of clauses 30.3(a)(vii) and (viii) in relation to the Pipeline Trust is reasonable on the basis the Trust is not registered as described in these clauses.

DBNGP Trustee's representation and warranties (clause 30.4 of the 2005 to 2010 terms and conditions)

1541. DBP has proposed to remove, from the proposed revised terms and conditions, the representations and warranties of the DBNGP Trustee to a shipper (clause 30.4 of the 2005 to 2010 terms and conditions). DBP submits that this change has been made for reason that the terms are not appropriate for a R1 Service.

1542. Alinta, Verve Energy and Rio Tinto all submit that clause 30.4 should be retained in the proposed terms and conditions.

1543. In response to these third party submissions, DBP indicates that the DBNGP Trustee warranty cannot be, and should not be, included in the proposed revised terms and conditions because the DBNGP Trustee is not a party to the R1 terms and conditions.

1544. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service, the Authority is of the view that the representations and warranties of the DBNGP Trustee should be maintained in the proposed revised terms and conditions.

Required Amendment 95

Clause 30 the proposed revised terms and conditions, in relation to representations and warranties of the DBNGP Trustee to a shipper, should be amended to be substantially the same as the existing terms and conditions.

Records and information (clause 31)

1545. Clause 31 of the proposed revised terms and conditions establishes terms for the preparation and maintenance of records and information. DBP proposes to remove a provision for the shipper to require the operator to provide information on planned expansions in capacity of the DBNGP for the following five years (clause 31(b) of the 2005 to 2010 terms and conditions). DBP submits that this change is in recognition of the type of service that is the R1 Service.

1546. Both Alinta and Verve Energy submit that clause 31(b) should be reinstated, but do not provide any reasons for this. BHP Billiton submit that the deletion of this clause should be rejected on the grounds that the information is necessary for the efficient investment in and operation and use of natural gas services; it allows shippers some scope to plan their own future gas consumption, operations and expansions.

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[532] DBP, 8 December 2010, Submission 36: Response to ERA Information Request 17 November 2010, Confidential.

1547. In its response to third party submissions, DBP maintains its reasons for its proposal to remove clause 31(b) in recognition of the type of service; the proposed R1 Service is not a T1 Service and does not provide all the rights of a T1 Service. DBP further submits that the reason why such a provision exists under the T1 Standard Shipper Contract is because under this contract a shipper has a right to expand under clause 16 (and clause 16 does not exist under the proposed revised terms and conditions for the R1 Service).

1548. Consistent with the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed revised terms and conditions for the T1 Service should be materially the same as the existing terms and conditions for the T1 Service. Accordingly, the Authority requires that the provisions of clause 31(b) of the 2005 to 2010 terms and conditions remain in the proposed revised terms and conditions.

Required Amendment 96

Clause 31 of the proposed revised terms and conditions, in relation to the preparation and maintenance of records and information, should be amended to be substantially the same as the existing terms and conditions.

Entire agreement (clause 34)

1549. DBP has proposed revisions to clause 34 of the proposed revised terms as follows:

> 34 Entire Agreement
>
> This Contract ~~and the Access Arrangement~~ constitutes the entire agreement between the Parties on the subject matter of this Contract and supersedes all prior negotiations, representations and agreements between the Parties.

1550. No submissions to the Authority addressed this proposed change to clause 34.

1551. The Authority accepts that the access arrangement is not part of the agreement between the parties and therefore not part of the contract and accepts the proposed amendment to clause 34.

Revocation, substitution and amendment (clause 38)

1552. Clause 38 of the proposed revised terms and conditions contains provisions to revoke, substitute or amend any provisions of the contract. DBP proposes changes to this clause to introduce a new provision (proposed clause 38(b)) that prohibits amendments to increase the shipper's contracted capacity under the contract, except in circumstances where the shipper is entitled to additional contracted capacity under the access arrangement. DBP submits that this change has been made in recognition of the type of service that is the R1 Service.

1553. Rio Tinto submits that it does not object in principle to DBP's proposed change, however, it is of the view that the clause is framed incorrectly because it is not clear that the shipper will ever be "entitled to additional contracted capacity under the access arrangement". For this reason, Rio Tinto submits that clause 38(b) should specify that "an amendment to increase contracted capacity may not be made if doing so would be inconsistent with the access arrangement/queuing policy".

1554. In response to Rio Tinto's submission, DBP submits that clause 38(b) is not required to be redrafted as shippers cannot contract outside of the queuing policy.

1555. The Authority agrees that it is not necessary to expressly state that shippers cannot contract outside the queuing policy. However, given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service the Authority is of the view that clause 38 of the proposed revised terms and conditions should be substantially the same as the existing terms and conditions.

Required Amendment 97

Clause 38 of the proposed revised terms and conditions, in relation to revocation, substitution and amendment, should be amended to be substantially the same as the existing terms and conditions.

Non-discrimination clause (clause 45)

1556. DBP has proposed to remove, from the proposed revised terms and conditions, a non-discrimination clause relating to the provision of information by the operator to shippers (clause 45.1 of the 2005 to 2010 terms and conditions) and the treatment of all shippers on an arms' length basis (clause 45.2 of the 2005 to 2010 terms and conditions). DBP submits that this change works better in practice and that the provisions are not appropriate for a R1 Service.

1557. BHP Billion submits that DBP's proposal to delete clause 45 from the terms and conditions should not be allowed as the clause is clearly required to ensure that the national gas objective and concepts of fair competition are met, given that key shippers on the DBNGP are related to the owners of the DBNGP.

1558. Rio Tinto raises similar matters, noting that two major shippers continue to be part owners of the pipeline. For this reason, Rio Tinto submits that clause 45.2, requiring the operator to treat all shippers on an arms' length basis, imposes an appropriate discipline on DBP and therefore should be retained. In contrast, however, Rio Tinto welcomes DBP's proposal to remove clause 45.1.

1559. In its response to third party submissions, DBP submits that the operator is required by law to operate the DBNGP on a non-discriminatory basis and the contractual obligation is therefore not necessary. Furthermore, DBP submits in response to the comments of Rio Tinto that there is only one owner who is also a shipper, not two. In any case, the non-discrimination obligations are not a requirement of the NGL and NGR so it is beyond power for the Authority to insist on the inclusion of this non-discrimination clause.

1560. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed revised terms and conditions for the T1 Service should be substantially the same as the existing terms and conditions for the T1 Service.

1561. In the absence of any reasons to explain Rio Tinto's support for the removal of clause 45.1, relating to the provision of information by the operator to shippers, the Authority is of the view that clause 45.1 and clause 45.2 (of the 2005 to 2010 terms and conditions) are reasonable and consistent with the National Gas Objective and should be maintained in the proposed revised terms and conditions.

Required Amendment 98

Clause 45 of the proposed revised terms and conditions should be amended to be substantially the same as clause 45 of the existing terms and conditions, which establish terms for non-discrimination.

DBNGP Trustee's limitation of liability (clause 47)

1562. DBP proposes to remove from the proposed revised terms and conditions, terms limiting the liability of the DBNGP Trustee (clause 47 of the 2005 to 2010 terms and conditions). DBP submits that this change has been made in recognition of the type of service that is the R1 Service.

1563. Rio Tinto submits that it has no in-principle objection to this proposed change, but acknowledges that it does not have adequate information about the structure of the DBP group to form a concluded opinion. In the absence of this information, Rio Tinto seeks to ensure that DBP's proposal is consistent with reasonable and common commercial objectives to manage commercial and operational risk by ensuring that it is contracting with:

- entities of financial and technical substance;
- entities who are in a position to deliver on commitments being made; and
- all entities which own are in a position to dispose of the pipeline assets.

1564. In response to Rio Tinto's concerns, the Authority notes that clause 47 was inserted at DBP's instigation to recognise limitations on the DBNGPT Trustee's ability to enter into contracts under its trust deed.

1565. Taking the above matters into consideration, the Authority is of the view that the removal of the terms limiting the liability of the DBNGP Trustee (clause 47 of the 2005 to 2010 terms and conditions) should not put shippers at any commercial disadvantage.

Schedule 1 – Access Request Form

1566. DBP proposes changes to Schedule 1 of the proposed revised terms and conditions to insert, at Schedule 1, the "access request form" so that it forms part of the proposed terms and conditions. DBP submits that this change is in the nature of an administrative change.

1567. No interested parties commented on the proposed changes to Schedule 1.

1568. The Authority notes that the content of the proposed access request form is substantially the same as the “reference service access request form” that is available from DBP’s website. The Authority notes, however, that the proposed access request form does include the DBNGP Trustee as a party who executes the form, unlike the reference service access request form that is available on DBP’s website.

1569. The Authority has considered the DBNGP Trustee in relation to other clauses of the proposed revised terms and conditions dealing with certain warranties and liabilities of the trustee. The Authority accepts that the inclusion of the “access request form” so that it forms part of the proposed terms and conditions is reasonable.

Schedule 2 - Charges

1570. Schedule 2 of the proposed revised terms and conditions details the charges payable under the contract. In addition to changes of an administrative nature, DBP proposes to remove references to tariffs that are applicable to the T1 service; that is, the T1 capacity reservation tariff and T1 commodity tariff. DBP submits that these changes are in recognition of the type of service that is the R1 Service.

1571. No interested parties commented on the proposed changes to Schedule 2.

1572. Consistent with the Authority’s decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that the proposed terms and conditions should contain provisions that are substantially consistent with Schedule 2 of the existing terms and conditions in relation to charges. That is, Schedule 2 of the proposed terms and conditions should detail the tariffs applicable to the T1 Service.

1573. The Authority has considered to reference tariffs elsewhere in this draft decision. Consistent with these considerations, the Authority requires Schedule 2 of the proposed terms and conditions to detail the T1 capacity reservation charge and T1 commodity tariff.

1574. With respect to the other charges that are detailed in Schedule 2 (i.e. the excess imbalance charge, hourly peaking charge, overrun charge and unavailable overrun charge) the Authority is of the view that the rates at which the other charges are determined should be as follows:

- The “excess imbalance charge”, of proposed clause 9.5(c), is to be determined at 200 per cent of the T1 reference tariff.
- The “hourly peaking charge”, of proposed clause 10.3, is to be determined at 200% of the T1 reference tariff.
- The “overrun charge”, of proposed clause 11.1(a), is to be determined at the rate specified in clause 11.1(b).
- The “unavailable overrun rate”, of proposed clause 11.6 and 17.8(e), is to be the greater of:
  - 250% of the T1 reference tariff; and

– the highest price bid for spot capacity that was accepted for that gas day, other than when the highest price bid was not a bona fide bid, in which case the highest bona fide bid.

Required Amendment 99

Schedule 2 of the proposed revised terms and conditions should be amended to detail:

- the "T1 capacity reservation tariff" and "T1 commodity tariff", as determined under this draft decision; and
- the rates at which other charges are determined under the proposed terms and conditions, being the:
  - "excess imbalance charge" at 200 per cent of the T1 reference tariff;
  - "hourly peaking charge" at 200% of the T1 reference tariff;
  - "overrun charge" at the rate specified in clause 11.1(b); and
  - "unavailable overrun charge" at the greater of:
    - 250% of the T1 reference tariff; and
    - the highest price bid for spot capacity that was accepted for that gas day, other than when the highest price bid was not a bona fide bid, in which case the highest bona fide bid.

Schedule 3 – Operating Specifications

1575. Schedule 3 of the proposed revised terms and conditions details the operating specifications for the DBNGP, such as the gas specifications. DBP proposes several changes to Schedule 3 and submits that the changes are for reason of what works in practice. The changes comprise:

- The addition of a definition for the term "extractable LPG", which means "LPG that that can be extracted from gas without causing the gas to fail to comply with the operating specifications for outlet points".
- The addition of gas temperature and pressure specifications (minimum and maximum) for inlet and outlet points.

1576. No interested parties commented on the proposed change to Schedule 3.

1577. The Authority notes that since the proposed revised terms and conditions were submitted the Gas Supply (Gas Quality Specifications) Regulations 2010 have come into effect. The Authority therefore requires that Schedule 3 be amended to delete the table at item 1 – Gas Specifications, and instead provide that the Operating Specifications are those as specified in the Gas Supply (Gas Quality Specifications) Regulations 2010.

1578. The Authority also notes that FBP proposes to amend Item 2 of Schedule 3 to the maximum temperature for inlet points. The proposed revised terms and conditions specify 45 degrees Celsius for all inlet points except 1-01 at which it is 60 degrees Celsius. The Authority is of the view that, in the absence of evidence to the contrary, the temperature should be the same for all inlet points so there is no discrimination between shippers (whether that is 45 or 60 degree Celsius).

Required Amendment 100

Schedule 3 in relation to Operating Specifications should be amended to:

- delete the table at item 1 – Gas Specifications, and instead provide that the Operating Specifications are those as specified in the Gas Supply (Gas Quality Specifications) Regulations 2010; and
- amend Item 2 – Gas Temperature and Pressure so that it is the one measurement applying to all inlet points.

Schedule 4 – Pipeline Description

1579. DBP proposes to include at Schedule 4[533] of the proposed revised terms and conditions a URL link to a pipeline description document on the Authority's website.[534] The pipeline description document is the document contained in Annexure A of DBP's 2005 proposed revised access arrangement information (21 January 2005) – "Description of the Gas Transmission System". DBP submits that the inclusion of this link is for practical reasons.

1580. No interested parties commented on the proposed change to Schedule 4.

533 Schedule 4 of the 2005 to 2010 terms and conditions is indicated to be "intentionally deleted"; that is, it is not used in the existing terms and conditions.

534 The URL indicated by DBP cannot be found on the Authority's website. The Authority believes that the document that is intended to be referenced is the document located at: http://www.erawa.com.au/cproot/3471/2/AAI_Annex_1_Description_of_Gas_Transmission_System.pdf

1581. The Authority notes that DBP has on its website a more recent pipeline description document, dated 22 September 2009, which DBP makes reference to in clause 2 of the proposed revised access arrangement. The Authority has considered the requirement for an access arrangement to identify the pipeline to which the access arrangement relates and to include a description of the pipeline at paragraph 25 and following of this draft decision. Consistent with these considerations, the Authority is of the view that Schedule 4 of the proposed terms and conditions should include a pipeline description that is referenced in and appended to the proposed revised access arrangement.

Required Amendment 101

Schedule 4 of the proposed revised terms and conditions should be amended to include the pipeline description that is referenced in and appended to the proposed revised access arrangement.

Schedule 5 – Existing Stations

1582. An "existing station", under clause 1 of the proposed terms and conditions, is indicated to mean an inlet station associated with an inlet point or an outlet station associated with an outlet point that:

- was installed and commissioned on or before 1 January 1995; or
- is the subject of a Facility Agreement (under clause 6.15) or similar agreement as at the capacity start date.

1583. DBP proposes to include at Schedule 5[535] of the proposed revised terms and conditions a list of existing stations and their designations. DBP submits that the inclusion of a list of existing stations and their designations into Schedule 5 is for practical reasons.

1584. No interested parties commented on the proposed change to Schedule 5.

1585. The Authority notes that the proposed list of existing stations in Schedule 5 are stations that are contained in the pipeline description document as at 22 September 2009 on DBP's website.[536] The Authority considers that the inclusion of Schedule 5 serves to clarify what the existing stations are and accordingly approves the inclusion of schedule 5 in the proposed revised terms and conditions.

1586. The Authority also notes that the proposed list of existing stations in Schedule 5:

- are stations that are contained in the pipeline description document as at 22 September 2009 on DBP's website; and

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535 Schedule 5 of the 2005 to 2010 terms and conditions is indicated to be "intentionally deleted"; that is, it is not used in the existing terms and conditions.

536 DBP, Dampier to Bunbury Natural gas Pipeline System: Description of the Gas Transmission System as at 22 September 2009, viewed 13 September 2010, <http://www.dbp.net.au/files/DBNGP_Pipeline_Description_22_Sept_2009_Rev6.pdf>

- appear to be slightly inconsistent, in that Schedule 5 groups several outlet points into 'north' and 'south' metro, the designation for 'WLPG' appears to have a typo, and 'TiWest Cogen' appears to be listed in Schedule 5 as Thomas Rd.

1587. DBP advises that this is not an inconsistency because the access contract provides that delivery occurs at the notional outlet point for these 2 sites.[537]

1588. DBP advises that additionally, in Schedule 5 existing station 'TiWest Cogen' should be updated to Thomas Rd to be consistent with the 22 September 2009 pipeline description document.

Schedule 6 – Curtailment Plan

1589. Schedule 6 of the proposed revised terms and conditions sets out the curtailment plan for both system curtailment and point specific curtailment.[538] DBP proposes various changes to the curtailment plan; indicating that the changes are in recognition of the type of service that is the R1 service. The changes comprise changes to:

- remove reference to the "aggregated T1 Service";
- include references to the "P1 service" and "B1 service" under certain sections of the curtailment plan;
- include the "Tp Service" as part of the curtailment plan, with a priority order of six (6) for both system curtailment and point specific curtailment;
- make it explicit that the "other reserved service" is other than the "Tp service" or "Tx service"

1590. No interested parties commented on the proposed change to Schedule 6.

1591. Given the Authority's decision to require amendments to the proposed revised access arrangement to remove the proposed R1 Service as a reference service and to include a full haul T1 Service, the Authority is of the view that Schedule 6 of the proposed revised terms and conditions should be amended to be substantially consistent with Schedule 8 of the existing terms and conditions.

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[537] DBP Confidential Submission 36 – Response to ERA Information Request of 17 December 2011.

[538] The curtailment plan was previously set out at clause 8 in the 2005 to 2010 terms and conditions.

Required Amendment 102

Schedule 6 of the proposed revised terms and conditions, which sets out the curtailment plan, should be amended to be substantially consistent with Schedule 8 of the 2005 to 2010 terms and conditions for the T1 Service.

Tripartite Deed (Schedule 7 of the 2005 to 2010 terms and conditions)

1592. DBP proposes to delete Schedule 7 ("Tripartite Deed") from the proposed revised terms and conditions. While DBP does not indicate the specific reason for this change, the Authority believes that this change is in the nature of a consequential change resulting from DBP's proposed changes to clause 25.2 ("Charges") of the proposed revised terms and conditions.

1593. The Authority has considered DBP's proposed changes to clause 25.2 at paragraph 1472 and following of this draft decision. Consistent with these considerations the Authority requires Schedule 7 to be retained.

Required Amendment 103

The proposed revised access arrangement should be amended to include a Schedule 7 that sets out the form of the tripartite deed that is entered into under clause 25.2 of the contract.

Terms and conditions for reference services other than the T1 Service

1594. Consistent with its decision to require amendments to the proposed revised access arrangement to include part haul and back haul services as reference services, the Authority is of the view that the proposed revised access arrangement should be amended to include relevant terms and conditions for these services.

1595. The Authority is of the view that the terms and conditions for the part haul and back haul services should be, to the extent applicable for these services, substantially the same as the terms and conditions established under existing access contracts for part haul and back haul pipeline services negotiated with shippers.

Required Amendment 104

The proposed revised access arrangement should be amended to include terms and conditions for the part haul service (i.e. the P1 Service) and back haul service (i.e. the B1 Service), as reference services, that are substantially the same as the terms and conditions established under existing contracts for part haul and back haul pipeline services negotiated with shippers.

Queuing Requirements

Regulatory Requirements

1596. Under section 2 of the NGL(WA) 'queuing requirements' mean the "terms and conditions providing for the priority that a prospective user has to obtain access to spare capacity and developable capacity".

1597. Under rule 48(1)(e) of the NGR, if an access arrangement is to contain queuing requirements[539], the access arrangement must set out the queuing requirements pursuant to rule 103.

> 103 Queuing requirements
>
> (1) An access arrangement must contain queuing requirements if:
>
> (a) the access arrangement is for a transmission pipeline; or
>
> (b) the access arrangement is for a distribution pipeline and the AER [ERA] notifies the service provider that the access arrangement must contain queuing requirements.
>
> (2) If the AER [ERA] gives a notification under subrule (1), the access arrangement must contain queuing requirements as from the commencement of the first access arrangement period to commence after the date of the notification (but this requirement lapses if the AER [ERA] by notice to the service provider, withdraws the notification).
>
> (3) Queuing requirements must establish a process or mechanism (or both) for establishing an order of priority between prospective users of spare or developable capacity (or both) in which all prospective users (whether associates of, or unrelated to, the service provider) are treated on a fair and equal basis.
>
> (4) Queuing requirements might (for example) provide that the order of priority is to be determined:
>
> (a) on a first-come-first-served basis; or

539 A note to r. 48(1)(e) of the NGR states that queuing requirements are necessary if the access arrangement is for a transmission pipeline. The DBNGP is a transmission pipeline, hence the access arrangement must contain queuing requirements.

(b) on the basis of a publicly notified auction in which all prospective users of the relevant spare capacity or developable capacity are able to participate.

(5) Queuing requirements must be sufficiently detailed to enable prospective users:

(a) to understand the basis on which an order of priority between them has been, or will be, determined; and

(b) if an order of priority has been determined – to determine the prospective user's position in the queue.

1598. The Authority has full discretion in relation to queuing requirements.[540]

1599. Rule 112 of the NGR describes the processes for access requests which include the following.

- The request must be made in writing and must:
- state the time or times when the pipeline service will be required and the capacity that is to be utilised; and
- identify the entry point where the user proposes to introduce natural gas to the pipeline or the exit point where the user proposes to take natural gas from the pipeline; and
- state the relevant technical details for the connection to the pipeline, and for ensuring safety and reliability of the supply of natural gas to or from the pipeline.

1600. The service provider must, within 20 business days after the date of the request, respond to the request by informing the prospective user:

- whether the service provider can provide the requested pipeline service; and
- if so, the terms and conditions on which the service provider is prepared to provide the requested pipeline service; or
- that the service provider needs to carry out further investigation to determine whether it can provide the requested pipeline service and set out a proposal for carrying out the further investigation.

DBP's Proposed Revisions

1601. Clause 5 of the proposed revised access arrangement deals with the submission and consideration of access requests and queuing requirements.

1602. The queuing requirements of clause 5.4 of the proposed revised access arrangement are consistent with the queuing policy under the existing access arrangement (2005-2010). The queuing requirements provide for:

- a single queue for all services, both reference and non-reference services; and
- a priority of access in accordance with the time that an access request is received or deemed to be received by DBP.

[540] Refer to r. 40(3) of the NGR.

1603. DBP proposes several revisions to the provisions of the access arrangement dealing with the submission and consideration of access requests and queuing requirements. Material revisions comprise:

- outlining the circumstances when an access request must be lodged by a prospective shipper (clause 5.2(b) of the proposed revisions);
- requiring an access request to state relevant technical details for connection to the pipeline and for ensuring safety and reliability of the supply of gas to or from the pipeline (clause 5.2(c)(v) of the proposed revisions);
- when more information is required to assess an access request, establishing a requirement for the operator to request the information within 20 business days of receiving the access request and to provide a proposal for further investigations (clause 5.3(b) of the proposed revisions); and
- amendments to the provisions that allow the operator to reject an access request (clauses 5.3(f) and (g) of the proposed revisions).

1604. DBP has not proposed any major revisions to the provisions of the access arrangement dealing with the queuing of access requests.

1605. In support of its proposed revisions, DBP has provided to the Authority further information in a supporting submission (#6). This includes a schematic overview of the process for the lodgement and assessment of access requests and the forms to be used by shippers seeking access.[541]

Submissions

1606. Rio Tinto's submission comments on clause 5.3 of the proposed revisions that relate to the processes for an access request. Rio Tinto submits that:

- it is difficult for a large corporation to obtain Board sign-off on an application form, as required by clause 5.3(d) to submit an access request, if that form is in effect a contingent liability for up to 15 years' capacity charges and the applicant has no clear idea of when or whether DBP will agree to grant access;
- the effect of this approach is to force the applicant to always apply for a non-reference service on non-standard terms and conditions; and
- a better mechanism would be the use of a non-refundable deposit if the applicant withdraws its application, or the ability for DBP to invoice the applicant if the application is withdrawn.[542]

541 DBP, 14 April 2010, Public submission #6: Explanation of queuing requirements.

542 Rio Tinto submission, 20 July 2010.

1607. Furthermore, Rio Tinto provides examples of where, in its opinion, DBP has too much discretion under clause 5.3 of the proposed revised access arrangement, increasing its bargaining power against an applicant. Rio Tinto also submits that the single queue approach as stipulated in clause 5.4(b) of the proposed revisions is not the most efficient or effective way to deal with applications. Rio Tinto asks the Authority to consider a more flexible approach, to allow more than one queue and so that only applications which are actually competing for comparable resources are queued against one another.

Considerations of the Authority

1608. The Authority has considered separately the parts of clause 5 of the proposed revised access arrangement that deal with the submission and consideration of access requests (clauses 5.1 to 5.3) and the parts that deal with the queuing of access requests (clause 5.4).

1609. The NGR do not require a full access arrangement proposal to include information about the processes for access requests. However, as DBP has included this information in its proposed revisions, the Authority has given consideration to whether the information is consistent with the provisions of rule 112 of the NGR and with the national gas objective.

1610. The Authority notes Rio Tinto's view that clause 5.3(d) of the proposed revisions, requiring an executed application form to submit an access request, is not commercially practical for large corporations. The Authority considers that it would be reasonable for DBP to offer, as an alternative to an executed application form, the option for a user to make a non-refundable deposit. This mechanism would in the Authority's view provide users with the opportunity to make commercially practical decisions; DBP with adequate security to maintain its commercial operations and better promote the national gas objective.

Required Amendment 105

Cause 5.3(d) of the proposed revised access arrangement should be amended to include the option for a user to choose between a non-refundable deposit for the submission of an access request or an executed application form.

1611. Rule 112 of the NGR establishes particular provisions for processing access requests. DBP's proposed revisions to clauses 5.1 to 5.3 effectively reproduce the provisions under rule 112 of the NGR. The Authority notes that Rio Tinto provides examples of where, in its opinion, DBP has too much discretion under clause 5.3 of the proposed revised access arrangement (Assessment of Access Requests) and is of the view that this increases DBP's bargaining power against an applicant. However, the Authority is satisfied that clauses 5.1 to 5.3 of the proposed revised access arrangement are consistent with rule 112 of the NGR and the national gas objective.

1612. Furthermore, the requirements of the NGR for an access arrangement to include provisions dealing with the queuing of access requests are materially the same as the requirements that existed under the former Gas Code.

1613. Rules 103(3) – (5) of the NGR specify that queuing requirements must:

- establish a process or mechanism for establishing an order of priority between prospective users in which all prospective users are treated on a fair and equal basis; and
- must be sufficiently detailed to enable prospective users to understand the basis for how the order of priority between them has been, or will be, determined, and if an order of priority has been determined – to determine the prospective user's position in the queue.

1614. The Authority has considered Rio Tinto’s view that a single queue approach is not the most efficient way to deal with a wide range of applications and is not necessarily best suited to achieving the national gas objective. The Authority notes that clause 5.4(g) of the proposed revisions provides that the operator may deal with an access request out of order provided that the access request being dealt with is “materially” different to the access requests which have the same or earlier priority dates.

1615. Rio Tinto submits that it is not clear from clause 5.4(g) what may or may not be dealt with out of order. Rio Tinto states, for example, clause 5.4(g) may or may not allow a 10 TJ/d Pilbara part-haul application, which can be accommodated within spare capacity or with minimal expansion, to bypass a 100 T J/d application to the Mid-West which is awaiting a large increment of developable capacity. Rio Tinto submits that only applications which are actually competing for comparable resources should be queued against one another.

1616. The Authority is of the view that the situation as described by Rio Tinto may well occur from time-to-time and on this basis the Authority considers that clause 5.4(g) of the proposed revised access arrangement should be amended to include explicit bypass provisions for applications in the queue to address such a situation. The Authority, while recognising that the DBNGP is currently fully contracted, is of the view that introducing an explicit provision to deal with potentially small users having access to and utilising existing capacity (when and if available) would encourage economically efficient use of the pipeline.

Required Amendment 106

Cause 5.4(g) of the proposed revised access arrangement dealing with the processing of access requests in the queue, should be amended to include explicit bypass provisions to allow applications in the queue for haulage services that do not require developable capacity to be processed ahead of applications that do.

1617. In the absence of any proposed material revisions to the queuing requirements, and subject to required amendments as set out above, the Authority is satisfied that the queuing requirements under clause 5.4 of the proposed revised access arrangement satisfy the requirements of rule 103(3) to (5) of the NGR and the national gas objective.

Extension and Expansion Requirements

Regulatory Requirements

1618. Under section 18 of the NGL(WA):

(a) an extension to, or expansion of the capacity of, a covered pipeline must be taken to be part of the covered pipeline; and

(b) the pipeline as extended or expanded must be taken to be a covered pipeline,

if, by operation of the extension and expansion requirements under an applicable access arrangement, the applicable access arrangement will apply to pipeline services provided by means of the covered pipeline.

1619. Under rule 48(1)(g) of the NGR, a full access arrangement proposal must set out extension and expansion requirements. Extension and expansion requirements are defined under section 2 of the NGL(WA).

Extension and expansion requirements means—

(a) the requirements contained in an access arrangement that, in accordance with the Rules, specify—

(i) the circumstances when an extension to, or expansion of the capacity of, a covered pipeline is to be treated as forming part of the covered pipeline; and

(ii) whether the pipeline services provided or to be provided by means of, or in connection with, spare capacity arising out of an extension to, or expansion of the capacity of, a covered pipeline will be subject to the applicable access arrangement applying to the pipeline services to which that arrangement applies; and

(iii) whether an extension to, or expansion of the capacity of, a covered pipeline will affect a reference tariff, and if so, the effect on the reference tariff; and

(b) any other requirements specified by the Rules as extension and expansion requirements.

1620. Specific provisions relating to extension and expansion requirements are set out in rule 104 of the NGR.

104 Extension and expansion requirements

(1) Extension and expansion requirements may state whether the applicable access arrangement will apply to incremental services to be provided as a result of a particular extension to, or expansion of the capacity of, the pipeline or may allow for later resolution of that question on a basis stated in the requirements.

(2) Extension and expansion requirements included in a full access arrangement must, if they provide that an applicable access arrangement is to apply to incremental services, deal with the effect of the extension or expansion on tariffs.

(3) The extension and expansion requirements cannot require the service provider to provide funds for work involved in making an extension or expansion unless the service provider agrees.

1621. ‘Incremental services’ are defined under rule 3 of the NGR as “pipeline services provided by means of an extension to, or expansion of the capacity of, the pipeline”.

DBP’s Proposed Revisions

1622. Clause 7 of the proposed revised access arrangement contains provisions that deal with:

- the obligations of the operator to extend the DBNGP and/or expand the capacity of the DBNGP;
- determining whether extensions or expansions will become part of the covered pipeline; and
- the effect of extensions and expansions on reference tariffs.

1623. DBP proposes revisions to the extensions and expansions policy of the existing access arrangement (2005-2010), including:

- setting out a range of tests that must be satisfied before the operator has an obligation to expand the capacity of the DBNGP (clause 7.1 of the proposed revisions); and
- when determining whether to treat an extension or expansion of the DBNGP as part of the covered pipeline, consideration may given to the extent to which capacity is a result of an expansion to be undertaken through the application of the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)* (clause 7.4(f) of the proposed revisions).

Submissions

1624. Rio Tinto submits that clause 7.1(a) of the proposed revisions, which provides that the operator is not required to extend the geographical range of the DBNGP, should be amended to make it clear that it refers to “geographic range” on a macro scale, so that it does not accidentally rule out the addition of a new inlet or outlet station, which would typically involve taking additional land into an easement or licence area.

Considerations of the Authority

1625. DBP has proposed revisions to the extension and expansion requirements of the access arrangement to incorporate a series of tests that must be satisfied before it will expand the capacity of the pipeline to meet the transportation needs of prospective users.

1626. The tests, as set out under clause 7.1 of the proposed revised access arrangement, are as follows:

- the operator is not required to extend the geographical range of the DBNGP;
- the expansion is technically and economically feasible and consistent with the safe and reliable provision of the service to which the expansion relates;
- DBP's legitimate business interests are protected;
- the prospective shipper does not become the owner of any part of the DBNGP without the agreement of the operator; and
- DBP is not required to fund part or all of the expansion (except in relation to a capacity expansion option, where the provisions of the capacity expansion option require the expansion to be funded by the operator).

1627. These tests essentially reproduce the requirements of section 6.22 of the Gas Code which has since been replaced by the NGL and NGR. The extensions and expansions policy under the existing access arrangement (2005-2010) cross references this section of the Gas Code. As such, the proposed revisions do not materially change the extensions and expansions requirements of the access arrangement.

1628. However, the Authority is of the view that these tests may modify the NGL and is of the view that they are no longer necessary in the access arrangement as the provisions of the NGL cover the requirements for extensions and expansions.

Required Amendment 107

Clause 7.1 of the proposed revised access arrangement, which sets out a series of tests that must be satisfied before DBP will expand the capacity of the pipeline, should be deleted.

1629. Clause 7.4(f) of the proposed revised access arrangement provides that, in considering whether to treat the extension or expansion as part of the covered pipeline the operator may have regard to the extent to which capacity is a result of an expansion to be undertaken through the application of the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)*.

1630. DBP has indicated to the Authority that clause 7.4(f) is necessary as projects initiated under the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)* may be funded by either DBP or third parties.[543] DBP submits that it requires the ability to elect whether the extension, expansion or enhancement becomes part of the covered pipeline so that the costs of such an extension or expansion are not added to the capital base where the costs are funded by a party other than DBP or a user.

1631. An expansion of the pipeline to be undertaken through the application of the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)* would be:

- an expansion to compensate for a reduction in the capacity of the pipeline resulting from a change in the gas quality specification; and
- undertaken for the purpose of providing the same level of services as were provided by the covered pipeline before the change in the gas specification.

1632. The costs of such an expansion would qualify to be added to the capital base for the pipeline under rule 79(2)(c)(iv) of the NGR, which provides that capital expenditure is justifiable if it is necessary to maintain the service provider's demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity).

1633. Rule 82 of the NGR provides for costs financed by users to be excluded from the capital base, but not costs financed by a third party who is not a user. As such the rules do not provide for the costs to be excluded from the capital base where they are financed by a third party.

1634. Without an explicit prohibition in the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)* or regulations, it may be argued that the capital expenditure should be allowed to be added to the capital base if such expenditure was consistent with the National Gas Objective. The Authority is of the view that the Office of Energy should seek to have the *Gas Supply (Gas Quality Specifications) Regulations 2010* amended to ensure that compensation for capacity is not also recovered from users (i.e. double recovery) and the physical capacity that is compensated for is deemed to be part of covered pipeline.

1635. To the extent that the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)* enables DBP to recover from a third party the cost of replacing capacity of the covered pipeline due to a broadening of the gas quality, such capacity is part of the covered pipeline by virtue of it being an expansion to neutralise the effect of the broader gas quality. The Authority is of the view that the capacity made available by the construction of additional assets (extra compression or looping), even if such capacity is replacing "lost" capacity, should be considered in the same way as any other expansion or extension. Therefore, such expansion should be covered.

543 Email correspondence from DBP to the ERA, 22 June 2010.

Required Amendment 108

Clause 7.4(f) of the proposed revised access arrangement, extensions and expansion requirements, should be amended by deleting clause 7.4(f). This clause provides that in considering whether to treat the extension or expansion as part of the covered pipeline the operator may have regard to the extent to which capacity is a result of an expansion to be undertaken through the application of the provisions of the *Gas Supply (Gas Quality Specifications) Act 2009 (WA)*.

Changes to Receipt and Delivery Points

Regulatory Requirements

1636. A 'receipt or delivery point' is defined under rule 3 of the NGR as "a point on a pipeline at which a service provider takes delivery of natural gas, or delivers natural gas".

1637. Under rule 48(1)(h) of the NGR, a full access arrangement proposal must state the terms and conditions for changing receipt and delivery points. Rule 106 further specifies the required provisions relating to the change of receipt or delivery point by a user.

> 106 Change of receipt or delivery point by user
>
> (1) An access arrangement must provide for the change of a receipt or delivery point in accordance with the following principles:
>
> (a) a user may, with the service provider's consent, change the user's receipt or delivery point;
>
> (b) the service provider must not withhold its consent unless it has reasonable grounds, based on technical or commercial considerations, for doing so.
>
> (2) The access arrangement may specify in advance conditions under which consent will or will not be given, and conditions to be complied with if consent is given.

DBP's Proposed Revisions

1638. Clause 8 of the proposed revised access arrangement is a new clause of the access arrangement that sets out provisions for a shipper to change inlet or outlet points under an access contract or relocate contracted capacity between inlet points or between outlet points. Clause 8 indicates that this may occur subject to:

- a requirement for the shipper to make a change request in writing;
- the operator consenting to a change request before any change or relocation becomes effective;
- the operator not withholding its consent to a change request unless it has reasonable grounds, based on technical or commercial considerations, for doing so.

1639. Clause 8.2 of the proposed revised access arrangement indicates that, for a reference service, the considerations that the operator will take into account in deciding whether to consent to a change request will include the considerations outlined in section 13 of the access contract terms and conditions, which relate to the control, possession and title of gas.

Submissions

1640. No submissions were received by the Authority about DBP's proposed changes to receipt and delivery points by a user.

Considerations of the Authority

1641. The provisions of clause 8 replace a cross-reference in the existing 2005-2010 access arrangement to section 3.10(c) of the Gas Code that is materially the same as rule 106 of the NGR. As such, the proposed revision of the access arrangement to include clause 8 is considered by the Authority to not constitute a material change to the provisions for a user to change inlet or outlet points or relocate capacity between inlet or outlet points.

1642. The Authority notes that clause 8.2(c) makes reference to the considerations outlined in section 13 of the access contract terms and conditions which relate to the control, possession and title of gas. The Authority considers that clause 8.2(c) should instead refer to section 14 which relates to the relocation of contracted capacity of existing inlet/outlet points to new inlet/outlet points.

Required Amendment 109

Clause 8.2(c) of the proposed revised access arrangement should make reference to section 14 (Relocation) of the access contract terms and conditions not section 13 (Control, Possession and Title of Gas).

1643. Apart from this required amendment, the Authority is satisfied that the provisions of clause 8 of the proposed revised access arrangement meets the requirements of rule 106 of the NGR.

Review and Expiry Dates

Regulatory Requirements

1644. Rules 49 and 50 of the NGR set out requirements in relation to submission, commencement and expiry dates.

> 49 Review submission, revision commencement and expiry dates
>
> (1) A full access arrangement (other than a voluntary access arrangement):
>
> (a) must contain a review submission date and a revision commencement date; and

(b) must not contain an expiry date.

(2) An access arrangement to which this subrule applies:

(a) may contain a review submission date or both a review submission date and an expiry date; and

(b) must, if it contains a review submission date, contain a revision commencement date; and

(c) must, if it contains no review submission date, contain an expiry date.

(3) Subrule (2) applies to:

(a) a full access arrangement that is a voluntary access arrangement; and

(b) a limited access arrangement for a light regulation pipeline.

50 Review of access arrangements

(1) As a general rule:

(a) a review submission date will fall 4 years after the access arrangement took effect or the last revision commencement date; and

(b) a revision commencement date will fall 5 years after the access arrangement took effect or the last revision commencement date.

(2) If a service provider, as part of an access arrangement proposal, proposes to fix a review submission date and a revision commencement date in accordance with the general rule, the AER [ERA] must accept that part of the proposal.

(3) The AER [ERA] has no discretion under subrule (2).

(4) The AER [ERA] may, however, approve dates that do not conform with the general rule if satisfied that they are consistent with the national gas objective and the revenue and pricing principles.

DBP's Proposed Revisions

1645. Clause 14 of the proposed revised access arrangement contains the review submission and commencement dates that are to apply to the access arrangement:

- the revised access arrangement is to commence on 1 January 2011 (or the date specified by the Authority when making its final decision on the proposed revised access arrangement);
- the review submission date for the revised access arrangement is four years after its commencement; and
- the revision commencement date for the next access arrangement is 1 January 2016 or the date the Authority specifies when making its final decision on the next access arrangement revisions proposal, whichever is later.

Submissions

1646. None of the submissions received by the Authority addressed the review and expiry dates in DBP's proposed revised access arrangement.

Considerations of the Authority

1647. The Authority has no discretion in relation to the review submission date.[544] However, the Authority can only approve the date proposed if is satisfied that the date is consistent with the national gas objective and the revenue pricing principles.

1648. The Authority is satisfied that clause 14 of the proposed revised access arrangement meets the requirements of rule 49 and rule 50 of the NGR and is consistent with the national gas objective and the revenue pricing principles.

Trigger Events

Regulatory Requirements

1649. Rule 51 of the NGR contains provisions for "trigger events", which allow the review submission date that is fixed in an approved access arrangement (201-2015) to be brought forward. The rule indicates that a trigger event may consist of any significant circumstance or conjunction of circumstances, such as, for example:

- a re-direction of the flow of natural through the pipeline;
- a competing source of natural gas becomes available to customers served by the pipeline; or
- a significant extension, expansion or interconnection occurs.

> 51 Acceleration of review submission date
>
> (1) The review submission date fixed in an access arrangement advances to an earlier date if:
>
> (a) the access arrangement provides for acceleration of the review submission date on the occurrence of a trigger event; and
>
> (b) the trigger event occurs; and
>
> (c) the review submission date determined, in accordance with the access arrangement, by reference to the trigger event, is earlier than the fixed date.

544 Refer to r. 50(3) of the NGR.

(2) A trigger event may consist of any significant circumstance or conjunction of circumstances.

(3) The AER [ERA] may insist on the inclusion in an access arrangement of trigger events and may specify the nature of the trigger events to be included.

1650. The Authority has full discretion in relation to trigger events.[545]

DBP's Proposed Revisions

1651. DBP's proposed revised access arrangement does not include any trigger events that are to apply during the access arrangement period.

Submissions

1652. Wesfarmers' submission raises the following points.

- DBP's proposal contains overly aggressive positions with respect to forecast capital and operating expenditure and an overly conservative position in relation to forecast demand, all of which will result in a higher reference tariff than is appropriate.
- Due to the effect of the abovementioned positions on the reference tariff, and also of the limits placed on varying a reference tariff during an access arrangement period by the NGR, it is crucial that the Authority scrutinises the figures and approaches contained in DBP's proposal to ensure that they are consistent with the NGR.
- If the Authority does not require the positions to be varied with respect to forecast capital expenditure, operating expenditure and demand, before approving DBP's proposal, it should include one or more trigger events in the access arrangement for 2011-2015.
- A trigger mechanism would enable adjustment of the reference tariff if any of the forecasts contained in the proposal vary substantially from the actual expenditure.[546]

Considerations of the Authority

1653. Consistent with the current access arrangement no trigger event is specified in DBP's proposed revisions.

1654. The Authority notes Wesfarmers' view to the effect that if DBP is not required by the Authority to amend its forecasts downwards, the Authority should require one or more trigger event in the proposed access arrangement. Wesfarmers is of the view that this would enable adjustment of the reference tariff if any of the forecasts contained in the proposal vary substantially from the actual expenditure.

[545] Refer to r. 40(3) of the NGR.

[546] Wesfarmers Chemicals, Energy & Fertilisers submission, 9 July 2010.

1655. The Authority has scrutinised the figures in the proposed revisions in relation to forecast capital and operating expenditure, and forecast demand, and is satisfied they are consistent with the NGR. As such, the forecasts should not vary substantially from actual expenditure. Therefore, a trigger mechanism to enable adjustment of the reference tariff in the next access arrangement should not be necessary.

1656. Also, as the pipeline is currently fully contracted, and is likely to be until the existing shipper contracts expire, the Authority is of the view that a trigger event is not necessary as the provisions of the access arrangement are unlikely to be utilised until sometime after 2016. However, if the Authority was to be presented with evidence that pipeline capacity will become available during 2011 - 2015 then it would consider imposing a trigger mechanism in the proposed revised access arrangement. The Authority is of the view that it is likely a trigger event will be necessary for the next access arrangement period.

1657. Taking the above into consideration, the Authority accepts DBP's proposal not to include a trigger event for the forthcoming access arrangement period.

APPENDICES

Appendix 1 Glossary

Term	
AER	Australian Energy Regulator
Authority	Economic Regulation Authority
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBP	DBNGP (WA) Transmission Ltd
ERA	Economic Regulation Authority
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
NGA	National Gas Access (WA) Act 2009
NGL	National Gas Law
NGL(WA)	Western Australian National Gas Access Law
NGR	National Gas Rules

Appendix 2 List of DBP Submissions

DBP Submissions
DBP Submission 1 - Background Information
DBP Submission 2 – Compliance Index
DBP Submission 3 – Pipeline Services
DBP Submission 4 – Basis for total revenue
DBP Submission 5 – Terms and Conditions Comparison
DBP Submission 6 - Explanation of Queuing Requirements
DBP Submission 7 – Capacity and Throughput Forecast
DBP Submission 8 – Rate of Return
DBP Submission 9 - Justification of Expansion Related Capital Expenditure
DBP Submission 10 – Actual Stay-in-Business Capital Expenditure (2005 to 2010) Justification and Forecast Stay in Business Capital Expenditure (2011 to 2015)
DBP Submission 11 – Forecast Capital Expenditure
DBP Submission 12 - Justification of Operating Expenditure
DBP Submission 13 - DBP Response to ERA Issues Paper
DBP Submission 14 - Response to Halcrow Pacific Issues Report / Request of Information
DBP Submission 15 - Clarification sought in relation to information request - revenue by pipeline service
DBP Submission 16 - clarification sought on aspect of the proposed tariff model - hard-wired numbers
DBP Submission 17: Response to Halcrow Pacific Issues Report / Request of Information. CONFIDENTIAL, Date Submitted: 25 June 2010.
DBPSubmission 18: Response to Halcrow Pacific Issues Report / Request of Information CONFIDENTIAL, 18 July 2010
DBP Submission 19 - clarification in regards to capex categories for tariff model, 12 July 2010
DBP Submission 20 - Data request in relation to NERA (2010) The Required Rate of Return on Equity for Gas Transmission Pipelines, 29 June 2010
DBP Submission 21 - clarification in relation to proposed tariff model - pipeline distances (II), 19 August 2010
DBP Submission 22 - Clarification in relation to the proposed tariff model - R1 reference tariff, 13 August 2010
DBP SUBMISSION 23: Response to Halcrow Pacific Issues Report / Request of Information CONFIDENTIAL, Date Submitted: 21 July 2010
DBP Submission 24 – SUBMISSION 24: Response to Halcrow Pacific Issues Report / Request of Information CONFIDENTIAL, Date Submitted: 23 July 2010
DBP Submission 25 – Clarification in regards to cash contributions for tariff model, 28 July 2010
DBP Submission 26 – Response to Third Party Submissions

DBP Submission 27 – Response to Rio Tinto Submission CONFIDENTIAL Date Submitted: 11 August 2010
DBP Submission 28 – clarification in relation to the Kemerton lateral
DBP Submission 29 - SUBMISSION 29: Response to ERA Information Request of 12 August 2010, CONFIDENTIAL, Date Submitted: 22 September 2010
DBP Submission 30 – clarification in relation to the BEP lease arrangements
DBP Submission 31 – Clarification in relation to the Kemerton Lateral
DBP Submission 32 – Clarification in relation to timing of audits
DBP Submission 33 – clarification in relation to revenue from non-reference pipeline services
DBP Submission 34 – BEP lease clarification
DBP Submission 35: Response to ERA Information Request of 28 October 2010, CONFIDENTIAL, Date Submitted: 7 January 2011
DBP Submission 36: Response to ERA Information Request of 17 November 2010, CONFIDENTIAL, Date Submitted: 8 December 2010 – Clarification in relation to query about Terms and Conditions
DBP Submission 37 – Response to Section 42 Notice – Information Request in relation to the BEP lease arrangements
DBP Submission 38: Response to ERA Information Request of 26 November 2010 CONFIDENTIAL, 24 December 2010
DBP Submission 39 – Clarification of cash contributions in the tariff model
DBP Submission 40 – Confirmation that the BEP Lease Agreement became unconditional on 17 December 2010
DBP Submission 41 – Stage 5A and 5B (interim) Audit Reports
DBP Submission 42 – Consideration of template for public tariff model

Appendix 3 Rate of Return

Theoretical basis of the CAPM models

1. This Appendix is devoted to a summary of key aspects from each of the versions of the CAPM.

Sharp-Lintner CAPM

2. The Sharp-Lintner CAPM explains the expected return, $E(r_t)$, on any financial asset i in terms of the rate of return on a risk-free asset, r_f, and a premium for risk, $(E(r_M)-r_f)\times\beta_i$, where $E(r_M)$ is the expected rate of return on a market portfolio of assets, and the term $(E(r_M)-r_f)$ represents the market risk premium (**MRP**):

$$r_e = r_f + (E(r_M)-r_f)\times\beta_i$$

where β_i is the equity beta of asset i, which measures the contribution the asset makes to the risk of the market portfolio, and is defined as:

$$\beta_i = \text{cov}(r_i, r_M)/\text{var}(r_M):$$

$\text{cov}(r_i, r_M)$ is the covariance between the return on assets i and the return on the market portfolio; and

$\text{var}(r_M)$ is the variance of return on the market portfolio.

3. DBP is of the view that the Sharp-Lintner CAPM is well accepted, and Australian regulators, including the Authority, have used the Sharp-Lintner CAPM to estimate the cost of equity for access pricing decisions. The Sharp-Lintner CAPM is well accepted, not because it provides the best estimates or forecasts of the rate of return, but because it provides an important insight into the nature of the relationship between risk and return.[547]

4. The Sharp-Lintner CAPM was developed from the Markowitz portfolio theory,[548] within the mean-variance framework,[549] and makes the key assumptions that investors:

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547 DBNGP Revised Access Arrangement Proposal Submission, page 13.

548 This theory provided the first rigorous measure of risk for investors and showed how one selects alternative assets to diversify and reduce the risk of a portfolio. It also derived a risk measure for individual securities within the context of an efficient portfolio. Based on this theory, Sharpe and several academicians extended the Markowitz's model into a general equilibrium asset pricing model that included an alternative risk measure for all risky assets (Reilly and Brown, 2006, Investment Analysis and Portfolio Management, 8th Edition, page 229.)

- choose between portfolios on the basis of the mean and variance of each portfolio's return, measured over a single period;
- share the same investment horizon and beliefs about the distribution of returns;
- face no taxes (or the same rate of taxation applies to all forms of income) and that there are no transaction costs; and
- can borrow or lend freely at a single risk-free rate.

5. In the Sharp-Lintner CAPM, investors are concerned about how the asset contributes to the risk of a large diversified portfolio such as the market portfolio, and not about how risky an individual asset would be if held alone.

Black CAPM

6. The Black CAPM was derived from the Sharp-Lintner CAPM, within the mean-variance framework, but without assuming the existence of a risk free rate asset and without assuming unrestricted borrowing and lending.[550] In Black's derivation of the CAPM, the return on a portfolio, known as the zero-beta portfolio $\left(E\left(r_z\right)\right)$, for which the return is uncorrelated with the return on the market portfolio, acts as the equivalent of the risk free return.

$$r_e = E\left(r_z\right) + \left(E\left(r_M\right) - E\left(r_z\right)\right) \times \beta_i$$

7. The main findings from the Black CAPM are that:
   - when β is low, the expected return predicted by the Sharp-Lintner CAPM is less than the expected return predicted by the Black CAPM; and
   - when β is high, the expected return predicted by the Sharp-Lintner CAPM is greater than the expected return predicted by the Black CAPM.

Merton's (1973) theory of inter-temporal choice

8. Merton suggested that the Sharp-Lintner CAPM and the Black CAPM are subject to theoretical objections because they were derived within the mean-variance framework.[551] Merton then derived a general form of the asset pricing relationship, using a standard model of inter-temporal choice from microeconomic theory. By doing so, Merton also dropped the assumption of a single time period as adopted in both the Sharp-Lintner CAPM and the Black CAPM.[552]

9. Merton's theory of inter-temporal choice presents that:

$$P_t = E_t\left[m_{t+1}; x_{t+1}\right]$$

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549 Markowitz developed and introduced the notion of a mean-variance efficient portfolio as one that: (i) provides minimum variance (risk) for a given expected return and (ii) provides maximum expected return for a given variance (risk).

550 Black, Fischer (1972), "Capital market equilibrium with restricted borrowing", *Journal of Business* 45, pages 444-454.

551 Robert Merton (1973), "An Inter-temporal Capital Asset Pricing Model", *Econometrica,* 4(15), pages 867-887.

552 DBNGP Revised Access Arrangement Proposal Submission, pages 15-16.

where:

P_t is the equilibrium asset price at time t;

x_{t+1} is the uncertain payoff on the asset at time $t+1$; and

m_{t+1} is the stochastic discount factor which is determined by the ratio of the marginal utility of goods and services consumption tomorrow (MU_{t+1}) and the marginal utility of goods and services consumption today (MU_t).

10. DBP admits that the theory of inter-temporal choice does not facilitate the development of asset pricing models beyond the above abstract presentation. As such, more specific representations of the model have been sought. DBP also states that a key issue for this research has been the question of what are the appropriate factors.

11. DBP submits that one such factor is the return on a portfolio of total wealth, because consumption is high when investor returns on a portfolio of all assets is high. DBP also states that it has been recognised that multiple factors are required to explain equilibrium asset prices, and that the Fama-French three-factor model is the most widely recognised model.

Fama-French three-factor CAPM

12. Fama-French three-factor CAPM (**FFM**) was developed from the inter-temporal CAPM. The FFM identifies three sources of un-diversifiable risk:

- the excess return to the market portfolio (the market risk premium, MRP);
- the value or growth risk premium, high minus low (**HML**) – the premium earned by high book value shares relative to low book value shares. In this asset pricing model, high-value firms have a high ratio between the book value of equity and the market value of equity ("book-to-market ratio"), whereas the opposite is the case for low-value firms (also known as growth shares); and
- the size risk premium, small minus big (**SMB**) – the premium earned by small shares relative to big shares. Small (big) firms have small (big) total capitalisation (i.e. equity at market value):

$$E(R_j) = R_f + b_j \times \left[E(R_M) - R_f\right] + h_j \times HMLP \quad + s_j \times SMBP$$

where:

b_j; h_j and s_j are the slope coefficients from a multivariate regression of R_j on R_m; HML and SMB;

$HMLP$ and $SMBP$ are the HML and SMB risk premia.

13. The FFM states that small firms and firms with high book-to-market ratios require additional returns to compensate investors for these additional risks. Accordingly, large firms and firms with a low book-to-market ratio have less risk and therefore investors require a lower rate of return.

Zero-beta Fama-French CAPM

14. DBP submits that, like the Sharp-Lintner CAPM, the Fama-French CAPM has been shown to underestimate expected rates of return on assets with low beta[553]. As such, like the Black CAPM, the zero-beta Fama-French CAPM is introduced. With this version of the CAPM, a risk free rate is replaced by the expected return on an asset, $E(r_z)$, for which the return is not correlated with the expected return on market portfolio.

$$E(R_j) = E(r_z) + b_j \times [E(R_M) - E(r_z)] + h_j \times HMLP \quad + s_j \times SMBP$$

Key issues in SFG's submission on the value of imputation credit

15. This Appendix is devoted to the SFG's submissions of key issues on the value of imputation credit.

Market practice

Key conclusions

16. First, SFG concludes that market professionals make no adjustment for imputation credits when estimating WACC or when valuing firms. This practice is equivalent to "setting gamma to zero".[554]

17. Second, SFG is of the view that the AER is wrong to conclude that "any assumed value for imputation credits (i.e. between zero and one) should not affect company values provided it is incorporated consistently in the firm's cash flows as well as the discount rate."[555]

Discussion

18. First, SFG provides evidence to support its view that the great majority of market professionals make no adjustment to either the cash flows or the discount rate to reflect any assumed value of imputation credits.

    - The great majority of independent expert valuation reports make no adjustment at all to either cash flows or discount rates to reflect any assumed value of imputation credits.[556]

553 Beta represents a measure of the volatility, or systematic risk, of a security or a portfolio compared to the market as a whole. A beta of 1 indicates that the security's price will move with the market. A beta of less than 1 means that the security will be less volatile than the market whereas a beta of greater than 1 indicates that the security's price will be more volatile than the market.

554 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 2.

555 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 2.

556 Lonergan, W., (2001), "The Disappearing Returns: Why Imputation Has Not Reduced the Cost of Capital," JASSA, Autumn 1, 1-17; and KPMG, (2005), "The Victorian Electricity Distribution Businesses Cost of Capital – Market practice in relation to imputation credits Victorian Electricity Distribution Price Review 2006 – 10."

- The great majority of Chief Financial Officers of major Australian companies (who between them account for more than 85 per cent of the equity capital of listed Australian firms) make no adjustment to either cash flows or discount rates to reflect any assumed value of imputation credits.[557]
- Published Queensland Government Treasury valuation principles require government entities to make no adjustment to either cash flows or discount rates to reflect any assumed value of imputation credits.[558]
- Credit agencies such as Moody's and Standard and Poor's also make no adjustments in relation to franking credits to any quantitative metric that they compute when developing credit ratings for Australian firms.[559]

19. Second, SFG agrees with the AER that Officer (1994) shows that, for a given value of gamma, the different consistent combinations of cash flow and discount rate produce the same estimates of the value of the firm. However, SFG argues that this does not imply that if a different value of gamma is selected, then the same value of the firm is still obtained. Using the example from the Officer (1994) framework, SFG concludes that:
    - the value of the firm is the same regardless of before-tax or after-tax cash flow and discount rate defined; and
    - the value of the firm is not the same when different values of gamma are used.[560]

20. As such, SFG concludes that the AER is wrong to conclude that "any assumed value for imputation credits (i.e. between zero and one) should not affect company values provided it is incorporated consistently in the firm's cash flows as well as the discount rate."

Assumed payout ratio

Key conclusion

21. On the Final Decision for the WACC Review for Electricity Transmission and Distribution Networks in May 2009, the AER concluded that the payout ratio of 1.0 is appropriate. SFG disagrees with the AER's decision on the following four areas.[561]

22. First, the AER concluded that a payout ratio of 1.0 is consistent with the Officer (1994) WACC framework, which assumes a full distribution of free cash flows. SFG argues that Officer does not assume a payout ratio of 1.0.

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557 Truong, G., G. Partington and M. Peat, (2008), Cost of Capital Estimation & Capital Budgeting Practice in Australia, Australian Journal of Management, 33 (1), 95 – 121.

558 Queensland Government Treasury, 2006, "Government owned corporations – Cost of capital guidelines," www.ogoc.qld.gov.au.

559 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 2.

560 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, pages 12-13.

561 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, pages 2-6.

23. Second, the AER concluded that a payout ratio of 1.0 is consistent with the AER's post-tax revenue model, which explicitly assumes a full distribution of free cash flows. SFG submits that this argument is wrong.

24. Third, the AER concluded that a payout ratio of 1.0 avoids any further costly debate on the estimation of the additional parameters that would be required to establish the "true" time value adjustment to retained imputation credits. However, SFG argues that there are no additional parameters to be estimated for the purpose of estimating the payout ratio. SFG is of the view that the appropriate approach is to simply adopt the empirical estimate of the payout ratio, which is 0.71.

25. Fourth, SFG argues that the same estimate of the payout ratio should be used throughout the WACC estimation. SFG considers that the AER uses the actual observed empirical estimate of 0.71 when estimating market risk premium, but uses an assumed payout ratio of 1.0 when estimating gamma.

Discussion

26. First, SFG argues that, in developing his framework, Officer (1994) is of the view that the payout ratio will be substantially less than 100 per cent (i.e. 1.0). Using the example from Officer (1994), SFG's calculations indicate that the hypothetical firm from Officer's framework creates 13.58 imputation credits and distributes 10.38 of them. As such, in that example, a payout rate is only 76 per cent.

27. Second, SFG notes that the AER itself states this is the wrong basis by which to estimate the payout ratio, by stating that:[562]

28. "the assumed utilisation of imputation credits should not be based on a benchmark efficient Network Service Provider. Rather, the AER considers that a best estimate of gamma should be based on a market-wide estimate for businesses across the Australian economy"; and that "a reasonable estimate of the annual payout ratio is the market average of 0.71."

29. Third, using the hypothetical example, SFG submits that there is a point (in a year) where the stored (undistributed) franking credits exceed the credits to be distributed in that year. As such, it is simply impossible for the AER to conclude that franking credits (both distributed and undistributed) are equally valued by investors and have the same effect on the cost of capital of Australian firms.[563]

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562 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 8.

563 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 16.

30. Fourth, in its WACC Review in May 2009, the AER's estimate of the market risk premium (**MRP**) is based on historical excess market returns which are differences between Australian stock market index and the yields for Commonwealth Government bonds each year. Associate Professor Handley, the AER's consultant on MRP, then "grossed up" these estimates for various assumed values of imputation credits. SFG argues that this grossing up procedure is based on the actual payout ratio of Australian firms, not on an assumed payout ratio of 1.0. As such, SFG considers that this is an inconsistency because the AER uses the actual payout ratio in estimating the MRP, whereas the AER used the assumed payout ratio of 1.0 in estimating gamma. SFG is of the view that consistency demands the same value of payout ratio should be used throughout the WACC estimation process.

Conceptual issues

Key conclusions

31. SFG submits that the weighted-average redemption rate approach, which was used by the AER to estimate the value of theta, has suffered from conceptual issues. SFG submits that this approach is based on a wrong perception by the AER and its consultant, Associate Professor Handley, that there is a single market consisting of n risky assets held collectively by m investors:

- The m investors must, between them, hold 100 per cent of the n assets; and
- The m investors own nothing other than the n assets

32. This means that: (i) none of the m investors can hold any assets outside the model; and (ii) there can be no investors outside of the model who can possibly buy any of the n assets inside the model. In other words, the derivation of the CAPM and subsequent models that are based on it require a closed system.

Discussion

33. SFG argues that when some possibilities are introduced, such as:

- any of the m investors inside the model can hold any assets outside the model, and
- there are any investors outside of the model who can possibly buy any of the n assets inside the model,

then the investor's optimisation problem changes, the market clearing condition changes, and the familiar Sharpe CAPM pricing relation, which Handley derives, cannot be derived.

34. SFG is of the view that it is impossible to derive any sort of equilibrium relationship when only a sub-set of investors and a sub-set of assets are considered. SFG argues that the "model" envisaged by Associate Professor Handley does not exist and cannot exist, and the CAPM pricing equation cannot be derived in the framework that he proposes.[564]

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[564] SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 16.

Appropriate time period for estimating theta

Key conclusions

35. SFG considers that in the absence of a structural break, a long sample of data should be used to estimate theta. This is consistent with the most basic statistical principles: all other things being equal, more data leads to more reliable estimates.

36. SFG argues that the empirical data should be used to determine if a structural break did occur, rather than assume it occurred in July 2000 when the Rebate Provision was introduced.[565]

Discussion

37. SFG considers that the only evidence of a structural break in July 2000, when the Rebate Provision was introduced, comes from the 2006 Beggs and Skeels study. However, SFG argues that this conclusion is based on non-sensible results, driven by estimation errors that could be expected when applying this sort of empirical estimation techniques to a small sample of data, as was done in the 2006 Beggs and Skeels study.

Inferring theta from market prices (using the dividend drop-off study)

Key conclusions

38. For the estimate of theta in its Final Decision on WACC Review in May 2009, the AER considers that the 2006 Beggs and Skeels' dividend drop-off study, which produces the estimate of theta of 0.57, is the most appropriate study. SFG argues that the 2009 SFG's dividend drop off study should be preferred because this study uses updated data from the 2006 Beggs and Skeels study.

39. In addition, Professor Skeels, one of the two authors in the 2006 Beggs and Skeels, concluded that the 2009 SFG study is the best estimate of theta of 0.23.

Discussion

40. The AER rejects the use of the 2009 SFG study on the estimates of gamma on the following grounds:

- incorrect corporate tax rates used;
- no test or adjustment for multi-collinearity;
- concerns about the reliability of some data;
- filtering, outliers and the stability of estimates; and

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[565] Prior to the July 2000 tax changes, there we three types of investors:

- Resident tax payers who could use franking credits;
- Resident untaxed individuals and entities who could not use franking credits; and
- Non-resident investors who could not use franking credits

However, as a result of the 2000 tax changes, resident untaxed individuals and entities could use franking credits since then.

- failure to remove "Black Friday" like observations from the data set.

41. SFG argues that even when all the above factors are taken into consideration, there is negligible change to the results.

Use of the tax statistics approach to estimate theta

Key conclusions

42. The AER uses the average redemption rates as reported by the Australian Taxation Office (**ATO**) in the tax statistics approach to estimate the value of theta in its WACC Review in May 2009. SFG argues that the alternative approach is to observe the market-clearing price of traded securities, known as the "dividend drop-off" approach. SFG considers that this alternative approach is better than the tax statistics approach because the traded price of securities can be observed from the market.

43. SFG concludes that the AER's decision to use the average redemption rates has been based on the following three propositions.[566]

    - First, gamma does not affect the cost of capital.
    - Second, the forcible removal of foreign investment would (in reality) not affect the cost of capital of Australian firms.
    - Third, the forcible removal of foreign investment would increase the estimate of theta under all methodologies.
    - SFG is of the view that the first two propositions are false, whereas the last one is only an assumption.

Discussion

44. SFG is of the view that the tax statistics approach, which uses redemption rates reported by the ATO, is not really needed to estimate theta. Under this method, theta is estimated as the proportion of Australian shares that are owned by resident investors. This method is based on two assumptions:

    - imputation credits received by non-residents investors are worthless to them; and
    - imputation credits received by resident investors are worth 100 per cent of face value to them.

45. In addition, SFG argues that redemption rates in the tax statistics approach does not reflect the value of imputation credits. The flow of this argument is as follows.

    - It is now assumed that the amount of foreign investment in Australia is forced to reduce for some reasons. In this circumstance, redemption rates must increase because a greater proportion of imputation credits will go to resident investors.

566 SFG Consulting, March 2010, *A regulatory estimate of gamma under the National Gas Rules*, Report prepared for DBP, page 4.

- On this basis, the estimate of theta would increase because redemption rates were used as the basis for the estimation.
- An increase in theta would result in a lower cost of capital because higher theta leads to higher gamma, given the same estimate for the payout ratio.
- As a consequence, the value of the Australian firms would rise.
- SFG is of the view that this outcome is not logical. SFG concludes that Australian firms would not be made better off by constraining the supply of foreign capital.

46. The next three paragraphs present SFG's view on the three propositions assumed by the AER.

47. First, SFG considers the AER's proposition that gamma does not affect the cost of capital. The AER concludes that, based on the advice of Handley, the inclusion of imputation credits will not affect company values as long as they are consistently recognised in the cash flows as well as the discount rate. Using a worked example from the Officer (1994) framework, SFG argues that this conclusion is wrong. When gamma was set to 0, the different approaches (i.e. before tax or after-tax) produce the same company values as each other. Also, when gamma was set to 0.65, the different approaches (i.e. before tax or after-tax) produce the same company values as each other – but the value of the company is different from the case where gamma was set to 0.

48. Second, SFG considers the AER's proposition that the forcible removal of foreign investment would (in reality) not affect the cost of capital of Australian firms. SFG is of the view that this conclusion is wrong because a limit on the amount of foreign equity in Australian market would lead to an increase in the cost of equity for Australian firms. In this case, SFG argues that the value of a firm would reduce and the policy to limit foreign investment in Australia would be criticised by firms, superannuation funds, and shareholders.

49. Third, SFG considers the AER's proposition that the forcible removal of foreign investment would increase the estimate of theta under all methodologies. SFG argues that this is only an assumption by the AER. Its argument can be summarised as follows:

- AER concludes that a substitution of foreign for domestic investment in the Australian equity market is expected to increase the equilibrium value of imputation credits and this in turn would be expected to increase in equilibrium value of theta. SFG admits that there is a general agreement that if the proportion of foreign investment decreases, the simple average redemption rate must mechanically increase in the same proportion. All other things being equal, this results in a proportional increase in the value of the firm.
- However, SFG argues that this reasoning cannot be applied to the techniques that use the prices of traded securities (i.e. the dividend drop-off study approach). This is because the estimates derived by a dividend drop-off study are stable over time, even though the degree of foreign investment changes from time to time.

Consistency issues

Key conclusions

50. SFG argues that, in its WACC Review in May 2009, the AER assumes a payout ratio of 1.0 when estimating gamma, but the AER adopts the lower actual payout rate of Australian firms when estimating the market risk premium. SFG concludes that a payout ratio of 1.0 should be used consistently throughout the process of WACC estimation.

51. SFG argues that it is inconsistent and wrong for the AER to set the value of cash dividends to 100 cents when the return on equity is estimated and to set the value of 75-80 cents per dollar when estimating gamma.

Discussion

52. The AER has used two different estimates of the value of cash dividends,[567] 100 cents and 75-80 cents, in deriving the WACC. Its decision is based on:

- the US dividend yield studies, which conclude that dividends are valued at 100 cents per dollar, in supporting its use of the standard CAPM; and
- the US dividend drop-off studies, which conclude that dividends are less than fully valued (75-80 cents per dollar), when estimating gamma.

53. SFG is of the view that consistency needs to be restored. An estimate of the value of cash dividends, either 100 cents or 75-80 cents, needs to be consistently used in estimating the cost of equity and gamma.

General observations

Key conclusions

54. SFG submits that, under the approach adopted by the Authority, a proportion of $\frac{\gamma T}{1-T\times(1-\gamma)}$ of the return to equity holders is assumed to come in the form of franking credits. SFG assumes that, with $\gamma=0.65$ and $T=30\%$, this amounts to a proportion of 22 per cent. Non-resident investors cannot utilise any franking benefits. As such, SFG argues that non-resident investors will receive a return that is 22 per cent below the equilibrium required return.

[567] Dividend drop-off studies regress the change of the stock price over the ex-dividend day on: (i) cash dividends; and (ii) franking credits. Some of the change in stock prices is ascribed to the cash dividend and the remainder is ascribed to the franking credit. As such, the estimated effect of franking credits is conditional on the value that is ascribed to cash dividends.

Appendix 4 Confidential Information

Appendix 5 Financial Model

A public version of the revenue and reference tariff model is published as a separate document and is available on the Authority's website.