SUBMISSION 9: Justification of Expansion Related Capital Expenditure

Public Version

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1. INTRODUCTION

1.1 On 1 April 2010, DBNGP (WA) Transmission Pty Ltd (DBP) filed the following documents with the Economic Regulation Authority (**ERA**):

(a) proposed revised Access Arrangement (**Proposed Revised AA**); and

(b) proposed revised Access Arrangement Information (**Proposed Revised AAI**).

1.2 These documents contain the information that the National Gas Access (WA) Act 2009 (**NGA**) (which includes the Western Australian National Gas Access Law text (**NGL**) and the National Gas Rules (**NGR**)) requires to be included in order to enable them to be approved by the ERA.

1.3 The ERA also issued a Regulatory Information Notice on 2 March 2010 (**RIN**).

1.4 In addition to the Proposed Revised AA and Proposed Revised AAI, a number of additional submissions on key issues will be or are to be filed to assist the Regulator to assess the Proposed Revised AA and to address the categories of information requested in the RIN. These included the following:

1. Background Information
2. AA & AAI Compliance Checklist
3. Pipeline Services
4. Basis for Total Revenue
5. Terms and Conditions Justification
6. Explanation of Queuing Requirements
7. Capacity and Throughput Forecast
8. Rate of Return
9. Justification of Actual expansion Capital Expenditure (2005 – 2010) (being this submission)
10. Actual Stay-in-Business Capital Expenditure (2005 – 2010)
11. Forecast Capital Expenditure (2005 – 2010)
12. Actual Operational Expenditure and Forecast Operational Expenditure

1.5 Accordingly, this submission is aimed at supplementing the information in the Proposed Revised AA and Proposed Revised AAI in order to:

(a) address the information requested by the ERA in the RIN in relation to the actual capital expenditure (in so far as it relates to the expansion of the capacity of the DBNGP); and

(b) enable the aspects of the Proposed Revised AAI relating to the actual capital expenditure (in so far as it relates to the expansion of the capacity of the DBNGP) to be approved by the ERA.

1.6 A separate submission is being provided to the ERA in relation to the justification of the actual capital expenditure incurred by DBP since 2005 on capital projects involving works other than for the expansion of the capacity of the DBNGP.

1.7 Since the commencement of the current access arrangement period, DBP has undertaken a significant and continual program of investment in the expansion of the capacity of the DBNGP. The investment is forecast to continue until 2011.

1.8 The level of investment is unparalleled since the pipeline was first commissioned in 1984.

1.9 The total expenditure that has been incurred up to the end of 2009 and which is expected to have been incurred up to 31 December 2010 is $1,827.96 million ($ December 2009), representing almost a 100% increase in the capital base as it was in 2004 (in $ December 2009).

1.10 The continual expansion program can conveniently be broken down into a variety of projects. However, while the decision to fund each of these stages of expansion was the subject of separate resolutions by the Boards of Directors of DBP and its related bodies corporate, in practice, the commencement of stages 5A and 5B overlapped the completion of the stages 4 and 5A (respectively). So, there was a continual flow of work being undertaken from 2005 onwards. The need to compartmentalise the continual expansion program into three distinct projects reflected the following drivers:

(a) The need to provide certain shippers with their requested capacity on time – DBP could not hold off on the commencement of the work until all shippers had committed.

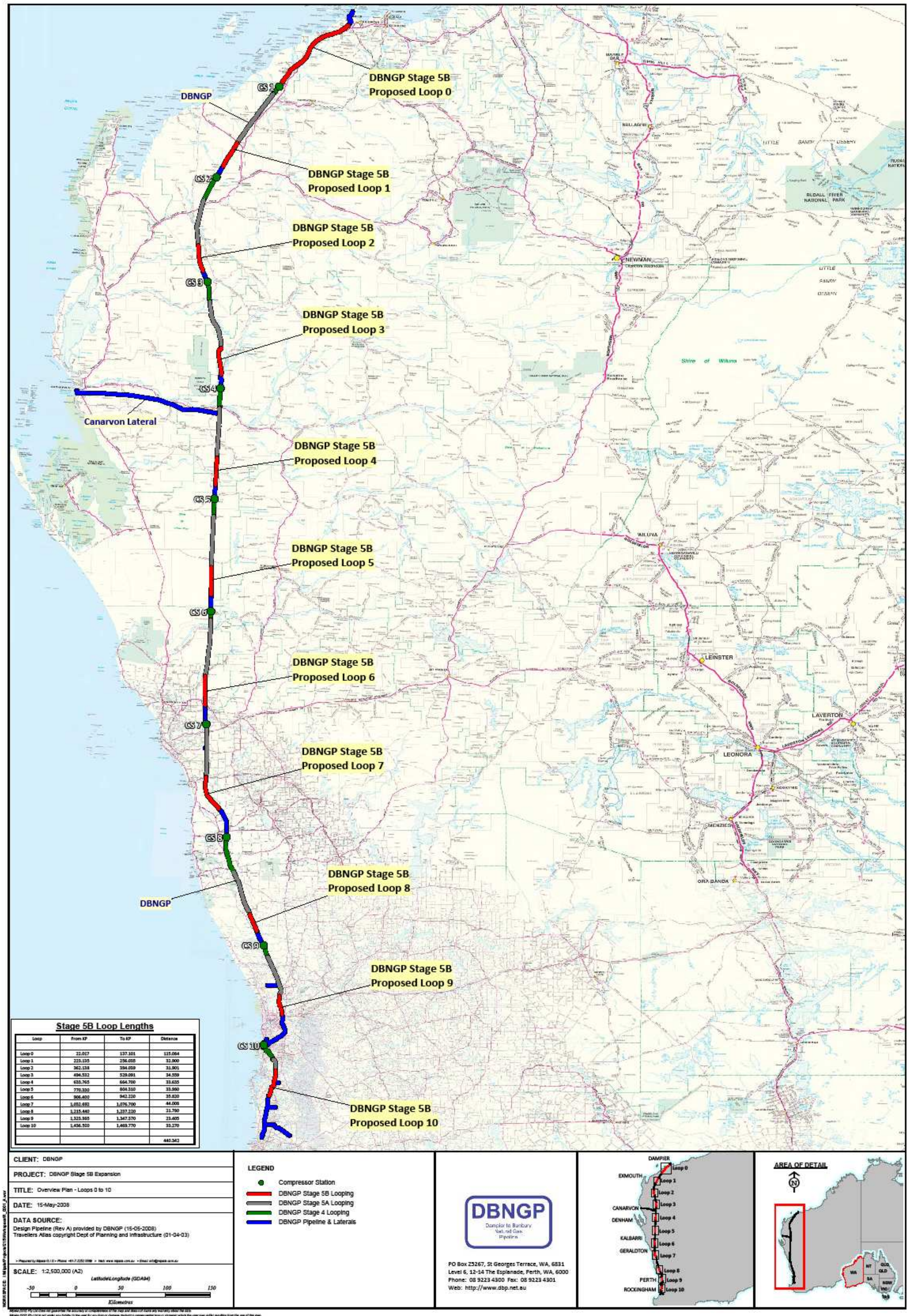
(b) the inability of the Board to commit to the funding of the entire expansion program without contracts being executed by shippers for the additional capacity

1.11 Following is a summary of the expenditure incurred (or, in the case of stage 5B, to be incurred), the work involved in the expansion program and the firm full haul capacity created by the expansion, broken down by each project:

Year	Expenditure (nominal $'000,000)	Assets constructed	Capacity created (Full Haul TJ)
Stage 4	446.71	194 km of mainline north looping and 23 km of loop 10 with new Solar Mars 100 units installed at CS1, 2, 3, 4, 6, 7, 9, and a Taurus T70 at CS10	124.9
Stage 5A	625.96	570.702 km of looping	93.0
Stage 5B	670.90*	440.312 km of looping and a Taurus 70 unit at CS10 and access to capacity on the Burrup Extension Pipeline (**BEP**) pursuant to a capacity lease	261.2

* this amount does not include an amount to reflect the expenditure to be incurred by DBP under the BEP Lease ($19.04m $2008), the details of which are explained in detail in section 16.

1.12 The extent of the works can be seen from the following map which shows where the looping works for each of the above stages has been undertaken.



Stage 5B Loop Lengths

Loop	From KP	To KP	Distance
Loop 0	22.017	137.101	115.084
Loop 1	223.135	256.035	32.900
Loop 2	362.138	394.039	31.901
Loop 3	494.532	529.091	34.559
Loop 4	633.765	664.700	33.635
Loop 5	770.330	804.310	33.980
Loop 6	906.400	942.220	35.820
Loop 7	1,032.692	1,076.700	44.008
Loop 8	1,215.440	1,237.220	21.780
Loop 9	1,323.965	1,347.370	23.405
Loop 10	1,436.500	1,469.770	33.270
			440.342

1.13 The capital expenditure made (and, in the case of 2010 expenditure, forecast to be made) in respect of each expansion project is summarized in the following table (the amounts are expressed in nominal terms – ie dollars of the day):

	Actual					Forecast	
	2005	2006	2007	2008	2009	2010	2011
Stage 4 Compression	-	52,701,923.50	153,622,428.67	-	9,534,363.08	-	-
Stage 4 Pipeline	-	-	229,784,242.94	-	-	-	-
Stage 4 Other	-	-	-	-	1,069,318.12	-	-
Stage 5A Compression	-	-	-	117,142,159.10	-	-	-
Stage 5A Pipeline	-	-	-	493,382,071.81	-	-	-
Stage 5A Other	-	-	-	1,437,548.43	-	14,000,000.00	-
Stage 5B Compression	-	-	-	-	-	155,000,000.00	-
Stage 5B Pipeline	-	-	-	-	-	450,000,000.00	-
Stage 5B Other	-	-	-	-	-	15,900,000.00	50,000,000.00
Linepack	-	-	-	-	4,450,252.25	-	-
Total Expansion Capital Expenditure	-	**52,701,923.50**	**383,406,671.61**	**611,961,779.34**	**15,053,933.45**	**634,900,000.00**	**50,000,000.00**

1.14 This continual expansion program is unprecedented in the history of the DBNGP and has been undertaken to meet the contracted demand of shippers. During the last 5 years, the activity to increase the capacity of the DBNGP has been undertaken using a works program that delivered all of the capacity on time and within the budget approved for each expansion project.

1.15 This feat is all the more exceptional given the economic conditions that existed during the 5 years – while the economic prosperity from 2005 (when the decision to fund the stage 4A was made) to late 2007 (being when the decision to fund the stage 5B expansion project was made) led to funds being more readily available than is presently the case, it gave rise to significant challenges for DBP such as significant increases in input costs and a severe shortage in skilled labour required to undertake some of the works.

1.16 The continual expansion was also required to be undertaken with minimal interruption to the ongoing operation of the pipeline – no small feat given the need to complete in excess of 50 tie-ins to the existing main line of the DBNGP at a time where the use of the pipeline was at record high levels.

1.17 With that context in mind, the purpose of this submission therefore is to substantiate the above capital expenditure as conforming capital expenditure so it can be rolled into the opening capital base for the proposed revised access arrangement.

1.18 It should be noted however that before this is done, there is some relevant background information. This is outlined in section 2of this submission

1.19 Section 3 of this submission then outlines a number of interpretational issues with the relevant provisions of the NGR.

1.20 Section 4 of this submission then outlines the expenditure that, in 2005, DBP forecast was to be made for the period from 2005 to 2010 and compares that with the capital expenditure that has actually been incurred during that period (and in the case of the 2010 year, the most up to date forecast of expenditure which will be made in this year).

1.21 The remaining sections of the submission then explain and justify:

(a) the expansion program for the 2005 to 2010 period; and

(b) the forecast expansion program for the 2011 year, against the criteria in Rule 79 of the NGR.

1.22 While DBP submits that there has been a single expansion program for the period from 2005 to 2010 and thereby a single item of expenditure for that period for the expansion, the remainder of the submission explains the expenditure by reference to each project.

2. EXPANSION OBLIGATIONS

2.1 At the time of Dampier Bunbury Pipeline's (**DBP's**) acquisition of the DBNGP in October 2004, much was made of the commitment given by the new owner to expand the capacity of the DBNGP and its implications for energy supply in WA. Extracts of various statements from the Minister for Energy at the time of the sale are contained in ATTACHMENT 1**.** The commitments then given by the owners remain in effect.

2.2 It is important therefore, to understand the expansion obligations that stemmed from this acquisition, as they form an important part in substantiating the investment as conforming capital expenditure under the Rule 79 of that National Gas Rules (which is expanded upon in a later section of this Submission).

2.3 The following information is in addition to that contained in DBP's submission #1 filed at or about the same time as this submission, in particular sections 3 and 4 of that submission.

2.4 The expansion of the capacity of the DBNGP was required to meet:

(a) contracted capacity committed to shippers under the existing shipper contracts that were renegotiated immediately prior to the acquisition of the pipeline in October 2004 (**SSCs**);

(b) DBP's obligations to the State under the Financial Assistance Agreement (**FAA**), an agreement entered into in October 2004 as part of the acquisition – in this regard, see section 3 of DBP's submission #3); and

(c) obligations in accordance with enforceable undertakings given to and accepted by the Australian Competition and Consumer Commission (**ACCC**) pursuant to the *Trade Practices Act 1974*.

2.5 Accordingly, the objectives of the expansion of the DBNGP were as follows:

(a) Complete each phase of the expansion program on time in order for DBP to be able to commence the delivery of gas to the shippers within the time frame agreed to with each shipper who requested capacity under the expansion program. These key timeframes for each stage of the expansion programs are detailed later in this submission.

(b) Deliver each expansion program with minimal disruption to current gas supply levels for existing shippers.

(c) Ensure that, given the very tight timetable for delivery of capacity to shippers, a contracting strategy is implemented to ensure work is completed on time, in the most cost effective manner and on budget. The best cost method for achieving the capacity and time requirements was through a combination of compression and looping. This is discussed further in this submission.

(d) Satisfy the requirements of the facility agreements with DBP's financiers. A separate Capital Expenditure Facility Agreement was entered into for each stage, the first of which was entered into at the time of the acquisition of the DBNGP. The others were entered into as part of the final investment decision for each project.

(e) Work is completed in full compliance with all occupational health and safety requirements, with minimal safety incidents occurring.

(f) Work is completed within a co-operative and stable industrial relations environment so as to minimise delays in the work schedule.

(g) The expansion program is conducted in a sustainable manner through strict adherence to the environmental management and cultural management plans.

(h) Manage all stakeholders in relation to project expectations.

Standard Shipper Contract Expansion Obligations

2.6 The Standard Shipper Contracts (**SSC**) were the outcome of contract negotiations with existing shippers in October 2004. Given DBP's non discrimination obligations, if any shipper (aside from Alcoa under its Exempt Contract) seeks access to Full Haul capacity on the DBNGP, DBP will make that capacity available on the terms and conditions of the SSC. The SSC contains a number of relevant provisions:

2.7 Clause 16 obliges DBP to expand the pipeline for an existing shipper requiring additional T1 capacity subject to:

(a) the shipper providing DBP 30 months notice of its additional capacity requirement;

(b) the shipper and DBP agreeing an amendment to the existing SSC which includes a capacity commencement date which can be no earlier than 24 months from the date of the agreement (unless otherwise agreed by the parties);

(c) the shipper meeting certain commercial requirement of DBP (for example, creditworthiness); and

(d) DBP being able to secure finance for the expansion on reasonable commercial terms and conditions for a verified amount.

2.8 As part of the sale of the pipeline in October 2004, several shippers exercised their rights to require DBP to fund an expansion of the capacity of the DBNGP under clause 16. [DELETED].

2.9 All subsequent expansions were undertaken as a result of either new shippers entering into new SSCs and then exercising rights under clause 16 of the relevant SSCs or existing shippers exercising expansion rights under their pre-existing SSCs.

FAA Expansion Obligations

2.10 Schedule 1 to the Financial Assistance Agreement, an agreement through which the State of Western Australia provided certain financial assistance to the owners of the DBNGP, requires that DBP expand the pipeline to the extent, and in accordance with the timetable, set out in schedule 1 of the agreement.

2.11 DELETED

2.12 DELETED

2.13 DELETED

2.14 Initial expansion commitments to Western Power Corporation (now Verve Energy), and to other shippers who lodged Access Requests prior to completion of the sale of the DBNGP in October 2004, were set out in Clause 9 of Schedule 1 to the FAA. These initial commitments (**Item 9 Commitments**) were for additional full haul capacity of 126.9 TJ/d. They were met by the Stage 4 expansion of the pipeline. The following table summarises the shippers involved in the Stage 4 expansion and when their capacity was delivered.

Contracting Party	Volume	Contractual Commencement Date	Actual Commencement Date
Western Power Corporation (now Verve Energy)	23TJ/day	1 April 2006	1 January 2006
Alcoa of Australia Ltd	2TJ/day	1 April 2006	1 January 2006
Alinta Sales Pty Ltd	23TJ/day	31 May 2006	31 May 2006
CSBP Ltd	4.9TJ/day	1 July 2006	1 July 2006
Western Power Corporation (now Verve Energy)	42TJ/day	1 November 2006	1 November 2006
Worsley Alumina Pty Ltd	10TJ/day	27 April 2007	1 November 2006
Alcoa of Australia Ltd	22TJ/day	1 January 2007	1 January 2007

2.15 With completion of Stage 4, DBP also satisfied obligations it has under Clause 10 of Schedule 1 to expand by no less than 100 TJ/day, and to invest up to $400 million, within 5 years of the completion of the sale in October 2004, subject to contracts being entered into with shippers for the additional capacity.

2.16 DELETED

2.17 Clause 11 of Schedule 1 sets out “Future Expansion Commitments” which require that DBP expand the DBNGP, for a shipper or prospective shipper, in accordance with clause 16 of the Standard Shipper Contract.

2.18 DBP is required by Clause 12 of Schedule 1 of the Financial Assistance Agreement, to use reasonable endeavours to finance the expansion.

2.19 These obligations cease on 1 January 2016, unless otherwise indicated in the Standard Shipper Contract.

2.20 The further expansions of the capacity of the DBNGP were undertaken pursuant to this obligation. [DELETED].

ACCC Undertakings expansion obligations

2.21 On 22 October 2004, the current owners of the DBNGP, and DBP itself, gave undertakings in accordance with section 87B of the Trade Practices Act 1974, whereby they allayed concerns the ACCC had with the potential implications of their acquisition of the pipeline for competition in energy markets.

2.22 Undertakings were given to invest up to $400 million to expand the capacity of the DBNGP to provide not less than 100 TJ/d to meet the known capacity requirements of shippers who enter into SSCs and for that expansion to be completed within five years of the date of the owners' acquisition of the pipeline. This undertaking was satisfied on completion of the Stage 4 expansion.

2.23 However, a general obligation to expand will remain in effect. In clause 5.6, the owners undertook to ensure that DBP offers to all prospective shippers who require a T1 service, a SSC that contains capacity expansion rights which are not materially less favourable than the capacity expansion rights in any other shipper contract for a T1 service.

2.24 DELETED

The extent and timing of expansion are driven by these obligations

2.25 Under the FAA and the ACCC Undertakings, DBP has obligations to expand the capacity of the DBNGP. Furthermore, DBP must offer shippers and prospective shippers' access to capacity on a non-discriminatory basis on the terms and conditions of, and at the price specified in, the SSC.

2.26 Since 2004, DBP has offered shippers access to capacity on the terms and conditions of the SSC. In accordance with those terms and conditions, DBP is now obliged to provide additional capacity within 30 months of its receiving a notice of an additional capacity requirement. The Access Requests DBP has received are the notices of additional capacity requirements required under the SSC. The dates on which these notices were received are such that DBP must, subject to its being able to secure the finance on reasonable commercial terms, expand the DBNGP to provide additional capacity in accordance with the timetables outlined in the tables in paragraphs 2.14 and 2.20 of this submission. DBP has met, or will meet, these timetables as outlined in the tables in paragraphs 2.14 and 2.20 of this submission.

3. THE CRITERIA FOR CONFORMING CAPITAL EXPENDITURE UNDER THE NGR

3.1 Under the NGR, capital expenditure can be rolled into the capital base if it is conforming capital expenditure.[1]

3.2 Rule 79 of the NGR provides that 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 on a ground stated in subrule (2).

3.3 The grounds outlined in Rule 79(2) of the NGR are:

(a) the overall economic value of the expenditure is positive. It is noted that, in addition to the considerations outlined in Rule 79(3) of the NGR to be taken into account to determine whether the overall economic value of expenditure is positive, Schedule 1, clause 7(2) of the NGR provides that the ERA must consider material economic value that is likely to accrue directly to electricity market participants and end users of electricity from additional gas fired generation capacity; 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) if 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).

3.4 The remaining paragraphs in this section of the submission outline DBP's interpretation of key terms used in Rule 79 of the NGR.

Regulator's discretion

3.5 It is important to note that in assessing whether the capital expenditure is conforming capital expenditure the ERA has a limited discretion.[2]

3.6 As provided for in Rule 40(2) of the NGR, this means that the ERA may not withhold its approval to capital expenditure as conforming capital expenditure if the ERA is satisfied that

[1] NGR Rule 77(2)(b)
[2] NGR Rule 79(6)

it complies with the applicable requirements of the NGA and is consistent with applicable criteria (if any) prescribed by the NGA.

3.7 The effect of this is that the ERA can only withhold its approval if the element is outside the range of acceptable alternatives that comply with the requirements relevant to this element. If the ERA considers that a change to the relevant element might be desirable to achieve more complete conformity between the element and the principles and objectives of the NGA, it is not allowed to reject the service provider's proposal to give effect to that view in the decision making process.

3.8 Under 79(1)(a) of the NGR, 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.

Prudency

3.9 In deciding whether expenditure is prudent, case law and regulatory precedent indicates that the regulator must ask what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true and the time they made a decision. In making decisions, a utility must take into account the best interests of its customers, whilst still being entitled to a fair return.

3.10 This was the test was applied by the Washington Utilities and Transportation Commission hearing in relation to Puget Sound Power & Light Company in the Fourth Supplemental Order made in cause U-83-54 in September 1984 at pp 32, 33, where the Commission said:

> *"The test this Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of expenditures."*

3.11 In Canada, the issue was considered at length in a decision of the Alberta Court of Appeal, Atco Gas & Pipeline Ltd v Alberta (Energy & Utilities Board) [2005] AJ 495, 2005 ABCA 122.

3.12 In its decision, the Board applied the following test of prudence:

(a) the utility would be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information that the owner of the utility knew or ought to have known at the time the decision was made;

(b) in making a decision, a utility must take into account the best interest of its customers while still being entitled to a fair return.

3.13 It is noted that Webster's New 20th Century Dictionary of the English language definition of prudent, provides as follows:

(a) capable of exercising sound judgment in practical matters; cautious or discreet in conduct; circumspect; sensible; not rash; characterised, dictated, or directed by prudence; as, prudent measures,

(b) synonyms include, circumspect, discreet, cautious, judicious, careful, considerate, sagacious, thoughtful, provident, frugal and economical.

3.14 The concept of prudence is therefore used to determine whether, at a particular time in question, an arrangement is or was appropriate and reasonable given the circumstances known or which ought to have been known.

3.15 The case law has also made it clear that an assessment of whether expenditure is prudence ought not to be based on hindsight. Webster's Dictionary defines hindsight as "perception of nature and demands of an event after it has happened". Applying this definition to the current context, the regulator must not impute knowledge to the service provider that the service provider could not reasonably have known at the time the utility made the decision being reviewed.

3.16 In deciding whether this test is met to be able to conclude whether expenditure is prudent, case law indicates that there is a presumption that expenditure by a service provider is prudent and that the regulator has the burden of proof to demonstrate that expenditure is imprudent. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown. There should not be excluded from the finding of prudency, investments which, under ordinary circumstances, would be deemed reasonable. Unless the Regulator can find expenditure which is dishonest or obviously wasteful or imprudent expenditure, it will be assumed to be prudent.

3.17 It is submitted that the if the following practical steps can be shown, then prudence and reasonableness in relation to expenditure will be proven:

(a) Planning - the ability to demonstrate that the service provider has considered an appropriate range of project contractual options given the legal and regulatory requirements and environment. Show that it has evaluated how this project differs from previous projects and that it has organised resources and developed policies and procedures to define clearly responsibilities and accountability.

(b) Prioritise - demonstrate that risk exposure areas have been identified, contingency plans developed for problems and flexibility maintained to adapt to changing project conditions.

(c) Management - demonstrate that a framework has been developed for the effective management of the project using resources, tools and reporting requirements, including timely corrective action when required.

(d) Collaboration - demonstrate that key stakeholders have been involved early in the process. Demonstrate the need for the project and that mechanisms are in place to monitor project conditions and take corrective action as they arise.

(e) Documentation - recognise the need to document all decisions and supporting rationales for actions throughout the planning and project process. This demonstrates that the utility has acted reasonably in preparing for and executing a major project.

3.18 Examples of evidence of imprudence include:

(a) poorly structured contracts not matched to project needs and the resource capabilities of the utility or the contractor;

(b) failure of effectively organised owner supervision;

(c) over-reliance on contracts and litigation to remedy problems after the fact, rather than through proper contract administration;

(d) inadequate financial planning and financial resources to match project needs;

(e) lack of information to make informed decisions, including inadequate cost, schedule, quality or regulatory compliance information;

(f) poor and slow resolution of engineering problems; and

(g) inability to bring the project to a conclusion and for the owner to accept operational responsibility.

Rule 79: new capital expenditure criteria – "overall economic value is positive"

3.19 The first test of Rule 79(2) – the overall economic value of the expenditure is positive – appears to replace the system-wide benefits test of section 8.16(a)(ii)(B) of the Code with a broadly based economic cost benefit test. The term "economic value" is not defined but, in his second reading speech on the National Gas (South Australia) Bill 2008, the South Australian Minister explained that:

> *The initial Rules will now include a "positive economic value" test for investment in existing pipelines designed to capture net increases in producer and consumer surpluses in upstream and downstream gas markets, whilst also capturing the system security and reliability benefits that were considered by regulators to constitute system-wide benefits.*

3.20 The intention to establish an economic cost benefit test is clearly indicated by the Minister's reference to the capture of net increases in producer and consumer surpluses. However, that test is not broadly based. Rule 79(3) limits its scope, requiring that, in deciding whether the overall economic value of capital expenditure is positive, consideration be given only to economic value directly accruing to the service provider, gas producers, shippers, and users of gas.

3.21 The transitional provisions of clause 6 of Schedule 1 to the National Gas Rules govern the application of Rule 79(3) in Western Australia until the end of the second access arrangement period commencing after the date of transition. Clause 6(2) states:

> *In making a relevant decision under rule 79(3) on whether the overall economic value of capital expenditure is positive, the AER [regulator] must consider not only 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.*

3.22 Clearly, clause 6(2) extends the scope of Rule 79(3) by allowing consideration of the economic value accruing to electricity market participants and to users of electricity generated from gas, in addition to the economic value accruing to the service provider, gas producers, shippers, and users of gas, in deciding whether the overall economic value of capital expenditure is positive.

3.23 Regulatory decisions by the Victorian Regulator-General, and by the ERA, have established that system wide-benefits are the positive externalities associated with pipeline expansion. That is, they are benefits accruing to others (other shippers, gas producers, users of gas, and possibly others) from new capital expenditure, and not benefits accruing to the pipeline service provider and to those shippers who contract for services provided using the facilities created by that expenditure.

3.24 System-wide benefits are, then, a part of the total economic benefits which are to be taken into account in determining overall economic value in accordance with Rule 79(2).

Rule 79: new capital expenditure criteria – "necessary to comply with a regulatory obligation or requirement"

3.25 DBP refers to section 4 of DBP's submission #1 filed on or about the date of this submission in relation to the definition of "Regulatory obligation or requirement" in the context of the ACCC Undertakings.

3.26 This term is defined in section 6(1)(b)(v) of the Western Australian National Gas Access Law text that results from modifying, according to Schedule 1 of the Act, the national Gas Law as set out in the South Australian Act Schedule and which is to be known in this submission to be the National Gas Access (Western Australia) Law. It is defined to include:

> *...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.*

3.27 As outlined in DBP's submission #1, DBP submits that the capital expenditure incurred to expand the capacity of the pipeline meets this criteria on the following basis:

(a) the expenditure is necessary to comply with the ACCC Undertakings; and

(b) the ACCC Undertakings are a regulatory obligation or requirement.

3.28 As to the second part of the definition, clearly the Australian Competition and Consumer Commission (the "ACCC") undertaking entered into by the Consortium (the "Undertaking") materially affects DBP's provision of pipeline services to which an applicable access arrangement applies.

3.29 DBP also submits that the Undertaking constitutes an instrument made or issued for the purposes of an Act of a participating jurisdiction.

3.30 Black's Law Dictionary defines "instrument" to mean "a written legal document that defines rights, duties, entitlements, or liabilities". The Undertaking clearly meets this definition. However, to meet the NGAL definition, an "instrument" must be made or issued under or for the purposes of an Act.

3.31 The Undertaking was created under section 87B of the Trade Practices Act 1974 (Cth) (the "TPA") to alleviate the ACCC's concern regarding the Consortium's proposed acquisition of DBNGP Holdings Pty Limited and the DBNGP Trust. The ACCC agreed not to take action under section 50 of the TPA on the condition that the Consortium and Epic Energy (WA) Transmission Pty Ltd entered into the Undertaking.

3.32 In Australian Petroleum Pty Ltd v ACCC[3], Lockhart J considered whether an undertaking made pursuant to section 87B was an "instrument" under the TPA, and therefore by definition an "enactment" under the Administrative Decisions (Judicial Review) Act 1977 (Cth) (the "ADJR Act"). The meaning of "regulatory obligation or requirement" under the NGAL and an "enactment" under the ADJR Act both include, amongst other things, an "instrument" made under an Act.

3.33 The undertakings in Australian Petroleum Pty Ltd v ACCC were given to "address the Commission's concerns" about the affect of a merger on a particular market. Lockhart J noted that the primary purpose of the undertakings was to allay the concerns of the

[3] *Australian Petroleum Pty Ltd v ACCC* [1997] 143 ALR 381

Commission such that the Commission would not need to intervene under section 50 of the TPA.

3.34 Lockhart J held that the undertakings were an "instrument" made under the TPA because the undertakings:

(a) were given for the purposes of section 87B in connection with a matter in relation to which the ACCC has the powers or functions under the TPA;

(b) owe their force and effect to section 87B of the TPA; and

(c) have the capacity to affect legal rights and obligations, and in fact do affect them.

3.35 As outlined above, DBP submits that the 2004 Undertakings are a regulatory obligation of requirement for the purposes of Rule 79(2)(c)(iii) of the NGR. This is so for the following reasons:

(a) The 2004 Undertakings materially affect the provision, by a service provider, of pipeline services to which an applicable access arrangement applies in that:

(i) The T1 Service that is the subject of a Standard Shipper Contract is a pipeline service;

(ii) The 2004 Undertakings materially affect the provision of the T1 Service by regulating key obligations under the Standard Shipper Contract for the T1 Service – being the non discrimination obligations, the tariff obligations and the expansion obligations; and

(iii) The T1 Service is provided by DBP – being a service provider of pipeline services to which the DBNGP Access Arrangement applies.

(b) The 2004 Undertakings constitutes an "instrument made or issued for the purposes of an Act of a participating jurisdiction". The Federal Court has determined that Undertakings given under section 87B of the Trade Practices Act (such as the 2004 Undertakings) are an "instrument". In *Australian Petroleum Pty Ltd v ACCC* [4], Lockhart J considered whether an undertaking made pursuant to section 87B was an "instrument" under the TPA, and therefore by definition an "enactment" under the *Administrative Decisions (Judicial Review) Act 1977* (Cth) (the "**ADJR Act**"). The meaning of "regulatory obligation or requirement" under the NGAL and an "enactment" under the ADJR Act both include, amongst other things, an "instrument" made under an Act. The undertakings in *Australian Petroleum Pty Ltd v ACCC* were given to "address the Commission's concerns" about the affect of a merger on a particular market. Lockhart J noted that the primary purpose of the undertakings was to allay the concerns of the Commission such that the Commission would not need to intervene under section 50 of the TPA. Lockhart J held that the undertakings were an "instrument" made under the TPA because the undertakings:

(i) were given for the purposes of section 87B in connection with a matter in relation to which the ACCC has the powers or functions under the TPA;

(ii) owe their force and effect to section 87B of the TPA; and

(iii) have the capacity to affect legal rights and obligations, and in fact do affect them.

[4] *Australian Petroleum Pty Ltd v ACCC* [1997] 143 ALR 381

3.36 Accordingly, 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 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.

The meaning of "Overall economic value of the expenditure is positive"

3.37 Assuming expenditure meets the prudency test, capital expenditure is justifiable, under Rule 79(2), if, among other things, the overall economic value of the expenditure is positive (Rule 79(2)(a)).

3.38 This test of Rule 79(2) – the overall economic value of the expenditure is positive – appears to replace the system-wide benefits test of section 8.16(a)(ii)(B) of the Code with a broadly based economic cost benefit test. The term "economic value" is not defined but, in his second reading speech on the National Gas (South Australia) Bill 2008, the South Australian Minister explained that:

> *The initial Rules will now include a "positive economic value" test for investment in existing pipelines designed to capture net increases in producer and consumer surpluses in upstream and downstream gas markets, whilst also capturing the system security and reliability benefits that were considered by regulators to constitute system-wide benefits.*

3.39 The intention to establish an economic cost benefit test is clearly indicated by the Minister's reference to the capture of net increases in producer and consumer surpluses. However, that test is not broadly based. Rule 79(3) limits its scope, requiring that, in deciding whether the overall economic value of capital expenditure is positive, consideration be given only to economic value directly accruing to the service provider, gas producers, shippers, and users of gas.

3.40 The transitional provisions of clause 6 of Schedule 1 to the National Gas Rules govern the application of Rule 79(3) in Western Australia until the end of the second access arrangement period commencing after the date of transition. Clause 6(2) states:

> *In making a relevant decision under rule 79(3) on whether the overall economic value of capital expenditure is positive, the AER [regulator] must consider not*

> *only 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.*

3.41 Clearly, clause 6(2) extends the scope of Rule 79(3) by allowing consideration of the economic value accruing to electricity market participants and to users of electricity generated from gas, in addition to the economic value accruing to the service provider, gas producers, shippers, and users of gas, in deciding whether the overall economic value of capital expenditure is positive.

3.42 The test of Rule 79(2)(a) – that the overall economic value of the expenditure is positive – will, in these circumstances, be critical to addition of the expansion related expenditure to the capital base of the DBNGP, and to its subsequent recovery via reference tariffs.

3.43 If Rule 79(2)(a) provides an economic cost benefit test for new capital expenditure, as may be inferred from the South Australian Minister's second reading speech, the economic benefits to be taken into account in determining overall economic value are:

(a) the benefits which accrue to the pipeline service provider, and to shippers who contract for services provided using the facilities created by the expenditure; and

(b) the benefits which accrue to others (other shippers, gas producers, and users of gas).

3.44 Regulatory decisions by the Victorian Regulator-General, and by the ERA, have established that system wide-benefits are the positive externalities associated with pipeline expansion. That is, they are benefits accruing to others (other shippers, gas producers, users of gas, and possibly others) from new capital expenditure, and not benefits accruing to the pipeline service provider and to those shippers who contract for services provided using the facilities created by that expenditure.

3.45 System-wide benefits are, then, a part of the total economic benefits which are to be taken into account in determining overall economic value in accordance with Rule 79(2).

4. COMPARISON OF 2005-2010 ACTUAL CAPITAL EXPENDITURE WITH ORIGINAL FORECAST

4.1 In the proposed revisions to the access arrangement that DBP submitted to the ERA in 2005, a significant expansion program was predicted. However, it has now become apparent that this forecast expansion program significantly underestimated the level of expenditure for the period.

4.2 This is evidenced in the table in section 9 of this submission which compares what was forecast for period in 2005 and what expenditure has actually been made (together with an updated forecast of expenditure for the 2010 calendar year).

4.3 There are several reasons for why the forecast expenditure submitted in 2005 is significantly different to that which has actually been made. The differences are attributable to:

(a) Differences in the volumes to underpin the expansion

(b) Differences in the assumed configuration for the expansion profile

(c) Differences in the unit rates applied for key cost inputs (such as looping construction rates and the cost of compressor units)

4.4 In relation to the volumes, the forecast was submitted to the ERA less than 6 months after the change in ownership of the pipeline. The forecast reflected very similar forecasts which underpinned the purchase price paid by DBP in October 2004 for the purchase of the DBNGP. While DBP's owners relied on an independent market forecast report to support the volume forecasts, the forecasts were prepared without the ability of the purchaser of the pipeline to discuss likely demand with the management team of the pipeline.

4.5 Further, the volume forecasts that underpinned the initial expansion were based on access requests that were in the queue at the time of the acquisition. Accordingly, the volumes for the initial expansion program (being stage 4) were accurate but at the time, there were no access requests in the queue to underpin either the stage 5A or 5B expansion projects.

4.6 In relation to the configuration for the expansions, the forecast submitted in 2005 to the ERA assumed an accurate expansion configuration for the stage 4 expansion because, at the time the forecast was submitted to the ERA, a decision had been made by DBP to fund the investment in DBP.

4.7 However, in relation to subsequent expansions, the configuration was dependent on the volume forecasts and the timing of those forecasts. As stated above in paragraphs 4.4 and 4.5, in hindsight this has not proven to be totally accurate for the post stage 4 volumes

4.8 Western Australia witnessed a significant increase in economic prosperity between 2005 and 2008. The magnitude and speed of this economic boom could not, even in 2004 (when the forecasts were derived), have been estimated with certainty.

4.9 In relation to the cost assumptions, the inaccuracy is largely attributed to the impact that the resources boom in WA had on key input costs such as labour and steel. As outlined above, this boom could not have been estimated with certainty, even in 2004 and 2005.

5. STAGE 4 PRUDENCY OF DESIGN

Summary of the Stage 4 Expansion design and expenditure

5.1 DBP's objectives for the expansion of the capacity of the DBNGP were:

(a) Complete each phase of the expansion project on time in order for all shipper commitments to be met. In this regard, it should be noted that commitments had been made to expand the pipeline as part of the acquisition of the DBNGP in 2004.

(b) Deliver the additional capacity with minimal disruption to current gas supply levels for existing customers.

(c) Ensure work is completed in the most cost effective manner and on budget.

(d) Work is completed in full compliance with all occupational health and safety and environmental requirements, with minimal safety incidents occurring.

(e) Complete the projects within a co-operative and stable industrial relations environment.

(f) Conduct the project in a sustainable manner through strict adherence to the environmental management and cultural management plans.

5.2 The expansion known as the Stage 4 expansion project, itself was broken down into various sub-stages over the period December 2004 to January 2007. The expansion of the capacity of the DBNGP to meet the contracted and forecast demand for gas transportation service was achieved through the following sequence of activities:

(a) installation of additional 10 MW gas turbine driven compressors at CS3 and CS9 – Stage 4A;

(b) installation of an additional Solar Taurus 70 gas turbine driven compressors at CS10 – Stage 4B;

(c) installation of 23 km of 26 inch looping south of Kwinana Junction – Stage 4C;

(d) installation of 194km of 26 inch looping of parts of the mainline between Dampier and Kwinana Junction, immediately downstream of all compressor stations except CS 10 – Stage 4D;

(e) installation of additional 10 MW gas turbine driven compressors at CS6 and CS2 – Stage 4E;

(f) installation of an additional 10 MW gas turbine driven compressor at CS4 – Stage 4F;

(g) installation of an additional 10 MW gas turbine driven compressor at CS7 – Stage 4G;

(h) installation of an additional 10 MW gas turbine driven compressor at CS1 – Stage 4H.

5.3 The expenditure made by DBP in connection with the Stage 4 Expansion Project is outlined in the following table:

	Actual				
	2005	2006	2007	2008	2009
Stage 4 Compression	-	52,701,923.50	153,622,428.67	-	9,534,363.08
Stage 4 Pipeline	-	-	229,784,242.94	-	-
Stage 4 Other	-	-	-	-	1,069,318.12
Total		**52,701,923.50**	**383,406,671.61**	-	**10,603,681.20**

Context for the assessment of prudency for the Stage 4 Expansion

5.4 As stated earlier in this submission, in assessing the prudency of the design and the expenditure incurred for the Stage 4 expansion, regard is to be had to the following factors:

(a) Planning - the ability to demonstrate that the service provider has considered an appropriate range of project and contractual options. Where applicable, the service provider should show that it has evaluated how this project differs from previous projects and that it has organised resources and developed policies and procedures to define clearly responsibilities and accountability.

(b) Prioritise - demonstrate that risk exposure areas have been identified, contingency plans developed for problems and flexibility maintained to adapt to changing project conditions.

(c) Management - demonstrate that a framework has been developed for the effective management of the project using resources, tools and reporting requirements, including timely corrective action when required.

(d) Collaboration - demonstrate that key stakeholders have been involved early in the process. Demonstrate the need for the project and that mechanisms are in place to monitor project conditions and take corrective action as they arise.

(e) Documentation - recognise the need to document all decisions and supporting rationales for actions throughout the planning and project process. This demonstrates that the utility has acted reasonably in preparing for and executing a major project.

5.5 As mentioned previously in this submission, the Stage 4 expansion program had to be undertaken to meet the contractual obligations owed to shippers for the expansion of the pipeline. Very tight timelines were agreed with shippers for the delivery of the additional capacity. These commitments on delivery of the additional capacity were given as part of the acquisition of the pipeline in October 2004.

5.6 The initial tranche of additional capacity was required to be provided as early as January 2006 – less than 15 months from when a decision was made to purchase the pipeline. Accordingly, there was a need to pre-order some key items of hardware (such as compressor units) before the acquisition had been completed.

5.7 Notwithstanding the speed by which a decision had to be made in connection with the funding of the investment for stage 4, systems and processes were implemented to ensure that DBP considered an appropriate range of project and contractual options, that they were appropriately evaluated, there was a mechanism in place to derive accurate costings for the project budget and there was an appropriate risk assessment undertaken. There was also in place a mechanism for independent reviews to be undertaken, not only for the board but also for the financiers of the project. These reviews included reviews as to:

(a) Whether the proposed expansion would deliver the required capacity

(b) Whether the budget was appropriately costed

(c) Whether the project schedule was likely to be met

(d) key contracts for the procurement of equipment and for the provision of key services such as looping construction.

(e) the likelihood of the costs meeting the regulatory criteria for rolling into the capital base.

5.8 Following is a chronology of events leading to the finalization of the contracts for the deliver of capacity to the investment decision made by the Boards of Director of DBP and its related bodies corporate:

Date	Action
2001-2004	Lodgment of access requests by shippers for additional capacity
2003 onwards	Discussions commence with shippers to renegotiate contracts to allow for (among other things) the expansion of the DBNGP
April 2004	Receivers and Managers and Administrators appointed to run DBP
April 2004	Process commenced for the sale of the DBNGP
27 October 2004	Orders placed by the Receivers and Managers for the purchase of long lead items required to enable additional capacity to be delivered in accordance with the timetables requested by shippers under the shipper contracts
27 October 2004	Execution of documentation by DBP to: • amend the shipper contracts to ensure the ongoing viability of the pipeline • commit to the expansion of the capacity of the DBNGP • commit to the timetable for the delivery of additional capacity requested by shippers
November 2004	Management teams assembled to investigate design options for expansion
November 2004	Establishment of new corporate and governance structures to allow for transfer of staff from Epic Energy to
November 2004	Management teams assembled to develop investment proposal for Board. Establishment of an owners committee / board sub-committee to provide guidance to management on the development of the investment proposal, including the development of pricing estimates
December 2004	Board approval obtained for: • The signing of a contract appointing external engineers for Engineering and Procurement services • The approval of a funding commitment to cover for the work plan to enable the investment proposal to be prepared.

Date	Action
December 2004 – May 2005	Continued development of Options, scheduling requirements and pricing estimates through the adoption of a Monte Carlo P85 pricing and risk assessment process
December 2004 – January 2005	Liaison with shippers to determine if there was any flexibility to extend their additional capacity delivery dates
January 2005	Establishment by the Board of the key financial metrics against which the board would make a decision on whether to fund the investment required for the expansion
February 2005	The Board approved the funding for the initial substage of the expansion, known as stage 4A – this was required to enable long lead items to be purchased in time to be installed and commissioned to meet the shipper's additional capacity delivery date.
February 2005	Engagement of financier's independent engineer to assess key aspects of the proposed project
March 2005	The board approved: • a contracting strategy for key contracts for the supply of services and procurement of equipment. The board also was updated on key changes on the cost estimate
April 2005	Management risk work shop to finalise recommendation for stage 4D option
6 May 2005	Date for approval of remainder of investment for stage 4
13 May 2005	Last date for the ordering of looping pipe to enable it to be delivered on time to be installed and commissioned in time to meet the shippers' additional capacity delivery date.

5.9 The ultimate configuration of the project enabled the breakup of the project into a number of sub-stages – Stages 4A-H. It can be summarized as follows:

(a) Sub-stages 4A-B and 4E-H "fully compressed" the pipeline given the configuration and pipeline licence constraints at the time (particularly in so far as the maximum allowable operating pressure of the pipeline is concerned).

(b) Sub-Stage 4A and 4E each involved the installation of 2 new compressor units. The other 4 sub-stages above involved the installation of only one additional compressor unit each.

(c) Substage 4C involved the installation of pipeline looping in the southern part of the pipeline system – downstream of CS10

(d) Sub-stage 4D involved the installation of 10 separate loops (downstream of each compressor station) totalling 194km in length.

5.10 A more detailed explanation of the work involved in each of these sub-stages is contained in ATTACHMENT 2.

5.11 In deciding on the configuration option for the remainder of the Stage 4 expansion once it had been fully looped (ie Sub-stages 4C and 4D), regard was had to the fact that the option chosen would have a significant and enduring effect on the configuration to use for subsequent expansion stages (including Stages 5A and 5B) and the costs of providing gas transportation services.

5.12 Proposals for expanding the capacity of the DBNGP for stage 4D initially considered only a looping option. Other options, including a mid-line compression option, were, at the time, considered to be the more costly means (both in terms of the capital and resultant non capital costs) of providing additional pipeline capacity.

5.13 However, with significant increases in international steel prices occurring in the early part of 2005, and a shortage of skilled labour driving up labour costs within Australia, looping became a much more costly option than it originally appeared to be. In these circumstances, mid-line compression had to be seriously considered as an option for expanding the capacity of the DBNGP. This is discussed in more detail in section 6 of this submission.

5.14 Accordingly, as part of its process for deciding whether to proceed with funding the Stage 4 expansion program, the DBP board sought fully costed advice on a number of options for the configuration of the expansion to deliver the Stage 4 capacity. However, this had to be undertaken in the context of:

(a) the shippers' additional capacity delivery dates and the consequences that existed for failure to provide that capacity on the date. There existed a significant liquidated damages regime under the shipper contracts for not making the required date; and

(b) the need for key items of plant and equipment (including primarily compressor turbines and the looping pipe). In the case of looping pipe, it had to be ordered by no later than the second week of May 2005.

5.15 DBP therefore examined a range of pipeline expansion options which, for the Stage 4D expansion, included:

(a) looping with pipe of 26 inches diameter, and other diameters;

(b) mid-line compression; and

(c) any of the options outlined in the 2 sub-paragraphs above but reconfiguring the DBNGP to allow for an increase in the maximum allowable operating pressure ("MAOP") of the DBNGP in accordance with proposed changes to Australian Standard 2885.1.

5.16 DBP's Board determined that the Stage 4D expansion program include 194 km of looping of the mainline pipe with pipe of 26 inch diameter. A more detailed description of the Stage 4D is outlined in section 6.

5.17 A more detailed analysis of the options considered for the sub-stage 4D design is outlined in the following section of the submission.

6. OPTION ANALYSIS – STAGE 4

6.1 As outlined in the earlier section of this submission, a number of options for the design of Stage 4D were considered at the request of DBP's Board. These options were outlined in a presentation made to the ERA in 2005 at the time the investment decision was made. A copy of this presentation is attached as Error! Reference source not found.**.**

Option #1 - Looping – 26" pipe

6.2 This expansion option involved the looping of nine of the northern mainline sections of the DBNGP – the construction of nine pipeline loops downstream of the existing compressor stations 1-9 for an estimated total length of 194 km of 26 inch (660mm) NB pipe.

6.3 Key components of the scope of work for this project are as set out below.

6.4 The following pre-construction needed to be undertaken would include:

(a) FEED, including approved construction drawings and alignment sheets;

(b) Final route topographic survey and route optimisation due to environmental, cultural heritage and land owner issues;

(c) Identification of sections of the pipeline route that will require special construction methods and/or procedures including sections that are restricted in terms of available working space;

(d) Environmental assessments, approvals and surveys;

(e) Cultural heritage survey;

(f) Geotechnical survey – for the mainline trench and river crossing works (primarily to identify areas of rock that will be encountered);

(g) Approvals by statutory authorities;

(h) Agreements with land owners and traditional landowners (through indigenous land use agreements);

(i) Procurement of all other materials and equipment;

(j) Placement of orders and commitment to critical subcontractors (eg camp, catering, etc);

(k) Establishment of a project site industrial agreement;

(l) Development of a construction execution plan and schedule and any other required management plans and procedures, including OHS, Quality Assurance;

(m) Development of quality welding and coating procedures;

(n) Mobilisation of construction equipment and materials;

(o) Establishment of site facilities including camps, project site offices and maintenance and storage facilities and communication systems;

(p) Locate and set up sources for supply of water for the project;

(q) Identify access roads and restrictions relative to the same that will have to be addressed and or work that will have to be undertaken prior to the commencement of the delivery of pipe to the right of way; and

(r) Liaison and notification involving relevant land owners and or local authorities.

6.5 A total of 194km of looping of the mainline of the DBNGP would be required for the 26 inch pipeline. It is to be undertaken downstream of each compressor station as follows:

(a) Downstream of CS1 – 12km

(b) Downstream of CS2 – 32km

(c) Downstream of CS3 – 25km

(d) Downstream of CS4 – 25km

(e) Downstream of CS5 – 22km

(f) Downstream of CS6 – 11km

(g) Downstream of CS7 – 5km

(h) Downstream of CS8 – 47km

(i) Downstream of CS9 – 15km

	Northern Loop 194km 26” Stage 4D	Southern Loop 23km 26” Stage 4C
Pipe Diameter	26” 660.0mm	26” 660.0mm
Total Meters	194,000m	23,000m
Light wall length	191,000m	22,500m
Light wall thickness	8.84mm	8.84mm
Heavy wall length	3,000m	500m
Wall heavy thickness	10.61mm	10.61mm

6.6 The pipe diameter and coating options were based on the following assumptions:

(a) The pipe coatings reviewed are the coatings that were, at the time, used on most recent Australian and international pipeline projects.

(b) Internal coating is required to improve the pipeline friction factor.

(c) The quantity of heavy wall pipe was estimated by the project team from initial takeoffs from the current pipeline in the same locations.

6.7 The pipe would be acquired, coated and supplied to site. This would require the following steps to be undertaken:

(a) Supply of bare steel pipe by a steel mill in Japan;

(b) Shipping of bare pipe from Japan to Malaysia for coating;

(c) Coating of the pipe in Malaysia;

(d) Shipping of coated pipe to ports in Western Australia;

(e) Transporting or stockpiling of coated line pipe from ports to stockpiles in the vicinity of the receiving ports in Western Australia; and

(f) Transporting of the coated line pipe to the Right of Way to be unloaded and strung by the construction contractor.

6.8 Due to the high diameter to thickness ratio of the pipe it would be susceptible to damage during ship loading, transit, and unloading processes, therefore would be imperative that the type of ships engaged to transport the pipe to and from the coating plants are self geared full open hatch box hold between deck vessels.

6.9 Shipping lines were approached to review their capabilities against the project's requirements. Due to a critical shortage of ships at the time it was necessary to engage several ships on a permanent time charter basis to support stage 4 of the project. Different sized vessels would be utilised between the pipe mill ports and the coating plants and the coating plants and Western Australian ports. It would be imperative to manage the shipping of finished bare pipe and coated pipe at the various locations on a timely basis to ensure production schedules remain unchanged.

6.10 A simultaneous survey of required specialised equipment for pipe handling was conducted with associated costs included in the price schedules.

6.11 Australian customs were approached to confirm the dutiable rate for importing coated line pipe and a rate of 5% of the capital value has been allowed in the cost estimates.

6.12 The project also involved the installation of the following systems:

(a) SCADA;

(b) Cathodic Protection; and

(c) Electrical and Instrumentation Systems;

6.13 The following associated facilities for each pipeline loop would also need to be constructed:

(a) New scraper stations;

(b) New valving;

(c) Tie-ins to the existing compressor station facilities;

(d) Installation of new mainline valve stations on the pipeline loops, parallel to and at locations corresponding with existing mainline valve stations; and

(e) Installation of permanent end of loop line valves, scraper station and crossover piping to the existing pipework.

6.14 Hot-taps would also need to be undertaken on the existing pipeline in order to tie-in cross-over pipeline to the new loop pipeline. (The associated supply interruptions are to be minimised by negotiating with shippers to reduce their throughput nominations to the absolute minimum at the times hot tapping is required.) Tie-ins at the compressor station end were via a compressor station shut down not requiring hot-taps.

6.15 Because of the distance of the looping involved, 4 rivers were crossed by the pipework. This required horizontal directional drilling to be undertaken to ensure that the pipe is laid in accordance with appropriate safety and environmental standards.

6.16 Hydrostatic testing, air drying and pre commissioning of the installed pipeline loops and associated mainline valves and facilities would also need to be undertaken.

6.17 The commissioning work that would need to be undertaken involves the introduction of gas into the pipeline and associated facilities.

Approach to looping

6.18 Given that the cost of line pipe was a significant component of the total costs for this option, DBP provides the following explanation of the approach that has been adopted in analysing the pipework required.

6.19 As a preliminary comment, DBP, through its project manager at the time (Alinta Asset Management (formerly Alinta Network Services Pty Ltd)), undertook a pre-tender phase which was aimed at eliminating high risk options or those which are not available due to other commitments. This was aimed at reducing the tender evaluation time so that the pipe order could be placed so that the pipework can be constructed and commissioned, in time to meet the obligations DBP owes to shippers to provide the developable capacity.

6.20 The following approach was adopted by DBP and its project manager, in order to best determine the appropriate suppliers to engage for the various aspects of the project:

(a) 10 API accredited international Pipe Mills from around the world were approached to determine available capacity and receive current pricing and schedule information to a 5% level of accuracy.

(b) Two shipping companies were approached to determine shipping availability and capacity to freight pipe to the various coating plants and proposed Western Australian ports.

(c) Seven coating plants were approached to determine coating strategy, plant capacity, availability, and current costing for internal and external coating of the line pipe at plants in Malaysia, Kembla Grange and in Western Australia.

(d) Port Authorities at Dampier, Geraldton and Fremantle were approached for all costs associated with bringing ships into the west coast ports.

(e) All import tariff duties for coated line pipe were confirmed from the government authority.

(f) A schedule of rates for inspection costs associated with linepipe manufacture, coating, load out and receipt activities and operations was ascertained.

(g) DBP and the project manager compared data from recent projects they had been involved in at the time backed up by some budget estimates to determine the costs of set up and operation of linepipe stock piles.

(h) Three specialised line pipe haulage freight companies were approached for the cost of transporting linepipe from ports to the stockpiles, and stockpiles to the ROW. As an alternative, the national rail carrier was asked to provide a costing estimate for transporting linepipe from the east coast Australia coating plants to Perth.

(i) Coastal shipping companies were approached for the cost of transporting line pipe from Kembla Grange to Fremantle.

(j) A review was undertaken as to the cost of product insurances for all aspects of project.

(k) An audit was conducted of available dedicated material handling equipment for 26” coated linepipe.

6.21 The following resulted from the above approach:

(a) In relation to line pipe, there was only one pipe mill in the world capable of producing 26 inch Electric Resistance Weld (“ERW”) pipe. ERW pipe is produced from hot rolled coil which has cost and availability benefits over plate steel which is used for Submerged Arc Weld (“SAW”) pipe. The cost benefit is significant.

(b) A second benefit of ERW linepipe is that it can be supplied in longer lengths which subsequently reduce the quantity of welding and non destructive testing (“NDT”) on this project. Joint coating and line coating costs are also reduced with the longer pipe lengths which in turn generates further cost savings.

(c) Of the 10 pipe mills approached, 5 mills indicated that they would not be in a position to offer capacity prior to February 2006.

(d) In relation to pipe coating, three coating options were considered in this process. They include single layer FBE, dual layer FBE and Trilaminate. The internal lining in all three cases is 50 micron epoxy. It is understood that certain external coatings will be preferred to others due to their resistance to handling and installation damage. The establishment of a dedicated on shore coating plant will require a 6 month lead time for establishment, and will rely heavily on no delays in the development application process.

(e) In relation to shipping, due to the high diameter to thickness ratio of the pipe it will be susceptible to damage during ship loading, transit, and unloading processes. Therefore it is imperative that the type of ships engaged to transport the pipe to and from the coating plants are self geared full open hatch box hold twin deck vessels.

(f) There was also an issue with a critical shortage of ships, thus limiting the choices for DBP in order to meet the required capacity start times.

(g) The two largest and most experienced coated linepipe haulage contractors have provided details of haulage costs and equipment availability. There is an identified need for the full time mobilisation of extendable semi-trailers to provide support for on shore logistics.

(h) The dutiable rate for importing coated line pipe has been allowed in the cost estimates.

6.22 The approach to the installation of the loops and associated facilities was based on undertaking the construction and installation phase of the Stage 4 project by implementing conventional and proven industry construction methods and procedures and the utilisation of conventional construction and specialised pipeline construction equipment.

6.23 The pipeline loops are to be installed, for the most part, within the existing DBNGP land access corridor. The WA Government has established an additional 70 meter services corridor parallel to the DBNGP corridor which can be used for re-routing of the pipeline or to provide a temporary working easement.

6.24 The use of subcontractors would be minimised, given the experience of the main alliance contractors and the capabilities of ANS to undertake much work “in house”. However, the following work was to be outsourced to subcontractors:

(a) Non destructive testing of welds;

(b) Supply, installation and operation of camps; and

(c) Installation of HDD river crossings; and

(d) Construction of looping.

6.25 In order to best ensure the provision of the additional capacity on time, the construction of pipeline looping would be undertaken by two separate and independent construction spreads and crews. Each spread will be made up of similar construction crews in terms of equipment and personnel and will have the capability and resources to execute all aspects of the project, including the following:

(a) Construction survey;

(b) Clear and grade the right of way;

(c) Upgrading and maintaining access roads;

(d) Unloading and stringing of loop line;

(e) Bending of pipe;

(f) Welding of pipe, including NDT and inspection;

(g) Coating of field joints;

(h) Excavation of loop line trench;

(i) Lowering in and tieing in of welded or coated mainline sections;

(j) Bedding and padding of the trench and pipe in sections of rock;

(k) Efficient required buoyancy control;

(l) Backfilling of pipe trench;

(m) Installation and tie ins of open cut roads and water crossings;

(n) Cleaning and reinstating the pipeline right of way;

(o) Hydrostatic testing and air drying; and

(p) Pre-commissioning.

6.26 A construction plan for the installation of the above facilities has been developed on the following basis:

(a) All work (both on and off site) will be undertaken by separate and independent crews to those installing the pipeline loops; and

(b) The installation of the facilities associated with the looping would be undertaken during the same period by the same contractor that is installing the 8 additional new compressor units at the existing compressor stations (ie for Stages 4A-C and 4E-H).

(c) The majority of the assemblies to be installed at all locations will be pre-fabricated off site and transported to each site for assembly and installation.

(d) The on site works at existing compressor stations and at the end of each loop, for the most part, will be undertaken and installed prior to the construction of the pipeline loop including the pre-testing where practical.

(e) Following the hydrostatic testing and drying of the pipeline, the pre-tested facilities and pipeline will be tied in to the loop line by means of a "golden weld".

(f) Main line valve stations are to be prefabricated off site and are to be installed following hydrostatic testing but before air drying of the pipeline loop.

(g) Existing site accommodation and facilities located at each compressor station are to be utilised, including additional temporary facilities that will need to be established for the installation of additional compressor units.

Option Analysis: Option # 2 – MAOP

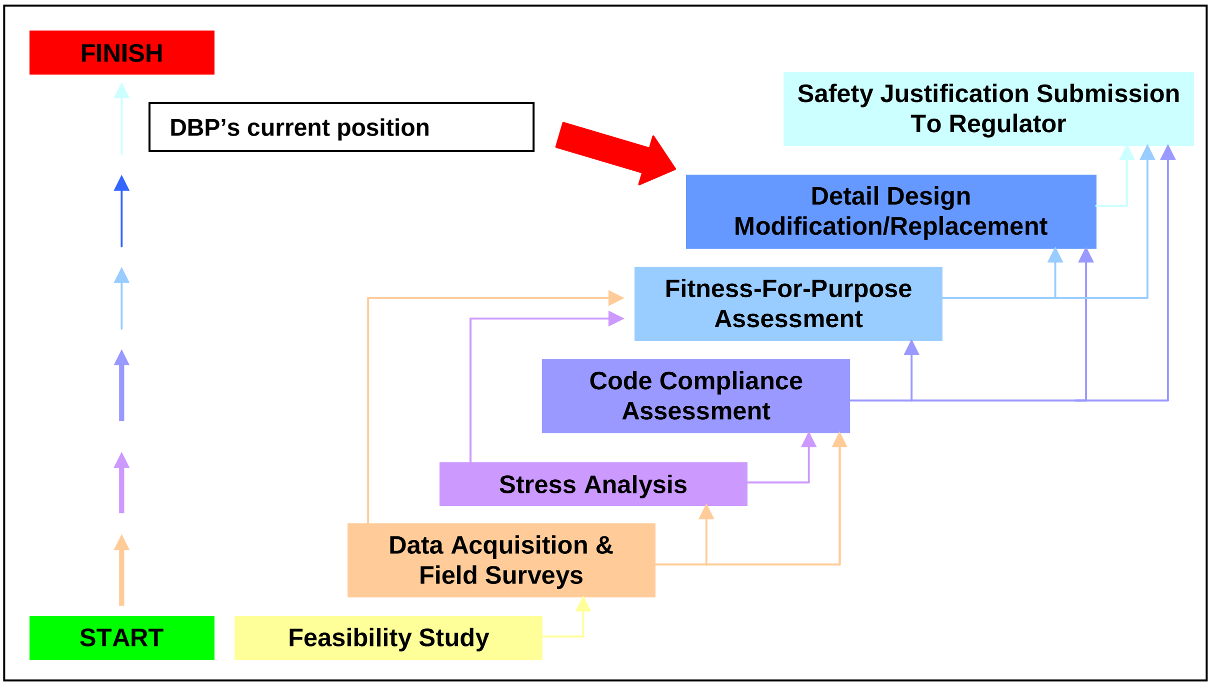
6.27 At the time proposed changes to Australian Standard 2885.1 were to, if implemented, allow the DBNGP to be operated at a pressure higher than the MAOP of 8.48 MPa. With relatively minor modifications to existing compression and metering facilities, DBP expected to be able to increase the MAOP to 9.3 MPA, and this could have provided an additional 40 TJ/d of T1 capacity which then could be used to provide firm service at a lower tariff than would otherwise be the case for shippers.

6.28 It would have meant a significant reduction in the configuration and therefore, forecast capital expenditure relating to Stage 4D if the changes were implemented and approved as part of the pipeline licences for the DBNGP.

6.29 It is important to note that given the delays in approving the changes to the standard and the need to proceed expeditiously with Stage 4 expansion, this option could only be seriously considered as part of subsequent expansion stages.

6.30 The locations and lengths of the loops required, if the MAOP were to increase to 9.3 MPa are, given the issues raised above in relation to this Option #2 was still to be determined.

6.31 DBP investigated increases in MAOP for a number of years, and was reasonably well placed to change to 9.3 MPa on the mainline between Dampier and Kwinana Junction if changes to AS 2885.1 are implemented. DBP's readiness at the time is shown in the following diagram.



6.32 Investigation of the configuration required as a result of an increase in MAOP for the pipeline downstream of Kwinana Junction was still to be carried out, and a recommendation on the capacity increment and modifications to existing facilities was expected to take around 12 months.

6.33 It should be noted, that the WA safety and technical Regulator (Department of Industry and Resources) had publicly objected to the proposed modifications to AS 2885.1.

6.34 The cost of the modifications to existing facilities required to increase the MAOP to 9.3 MPa had been broadly estimated at $25 million.

6.35 DOIR's certification of the up-rated DBNGP would need to have been obtained relatively quickly (probably by the beginning of July 2005) to allow sufficient time for the manufacture, delivery to site, and installation of either mid-line compression units, or pipe for looping.

6.36 DBP understanding at the time was that the timetable for consideration of proposed changes to AS2885 by the relevant committee established by Australian Standards (known as ME38) meant that any change would not have been implemented until at least August 2005.

6.37 Even if this timeline was achieved, amendments to the pipeline licences for the DBNGP would have been required to reflect the changes in AS2885. This is a further process that ordinarily would take additional time. Given the public position of the WA safety and technical Regulator on this issue at the time, there was real probability that the changes to the licence would take some significant time.

6.38 Accordingly, the ability to incorporate any of the benefits of a change to AS2885 into the configuration for Stage 4 were somewhat limited, because orders for pipework and compressors must be placed before the likely outcome was known.

6.39 In light of the above, and the financial ramifications for DBP if it did not commission the additional capacity on time, it was determined by the Board of Directors that this option would be an unacceptable risk for DBP to proceed to place orders on the assumption that the pipeline licence will be altered to reflect likely changes in the AS2885.

Option # 3 – Mid-line compression

6.40 The mid-line compression option for stage 4D would have involved the installation of additional compressors at new compressor stations to be located between the existing stations. These compressors are additional to those required for stages 4A-C and 4E-H.

6.41 Eight mid-line compressors would be required to meet forecast demand for gas transportation service at the end of 2007, and were expected to be required downstream of existing Compressor Stations 1, 2, 3, 4, 5, 6, 7 and 9.

6.42 At 2005 prices, adoption of the mid-line compression option was forecast to result in slightly lower capital cost (relative to the cost of looping), but likely to result in higher operating and maintenance costs in the future, therefore resulting in an overall more expensive cost for expansion.

(a) A structured tender process would be used for supply of the gas turbine drivers and compressor units. [DELETED]

6.43 DELETED

6.44 The nature of work for this option was likely to be largely similar to the work to be undertaken for compressors being installed as part of Stages 4A-C and 4E-H, the details of which are outlined in ATTACHMENT 2 together with additional work required to reflect the fact that construction will be taking place at a greenfields site.

7. ANALYSIS OF STAGE 4 OPTIONS

7.1 A detailed risk analysis of the above options was undertaken by DBP in deciding on the appropriate expansion program. The analysis covered technical risks, commercial risks, regulatory risks, construction risks and operational risks. The risk assessment outlines both risks and measures which are to be undertaken to manage the risks to a level acceptable to DBP.

7.2 The risk assessment was carried out in accordance with the relevant Australian Standard for risk assessment. This involves an assessment of project risks before and after treatment, against the criteria outlined in the matrices outlined below.

Risk Map
Before Treatment

			Consequence				
			Insignificant 1 Up To $1,000	Minor 2 Up To $10,000	Moderate 3 Up To $100,000	Major 4 Up To $1,000,000	Catastrophic 5 Over $1,000,000
Likelihood	A Almost Certain	95%					
	B Likely	80%					
	C Moderate	50%					
	D Unlikely	20%					
	E Rare	5%					

7.3 The following risks were identified for the Midline Compression Option.

(a) With more compressors being relied upon to provide capacity, this might adversely impact on DBP's ability to provide Tranche capacity services based on the same compressor unit availability assumptions for determining the Tranche 1 Capacity as currently exist. This was rated as a catastrophic risk.

(b) Inability to recover costs from shippers under existing contracts given the structure of the tariff adjustment provisions under these contracts. This was rated as a catastrophic risk.

(c) Regulatory risk arising from the inability to configure expansions to precisely meet contracted demand.

(d) Regulatory risk of whether the costs of complying with climate change reform could be passed through to customers, particularly with increased compressor usage under the midline compression option leading to higher emissions of greenhouse gases.

(e) Regulatory risk arising from the doubt as to whether compression costs could be included as New Facilities Investment within the definition of the Code.

(f) Operational difficulties in optimising capacity tranches as a result of increased compression on the system.

(g) An adverse impact on capacity as a result of compressor plant being rotated.

(h) It is more difficult to optimise the operation of the pipeline adopting a midline compression option.

(i) There could be an adverse impact on the integrity of the pipeline with additional compressors being installed.

(j) Whether more parts of the system would be exposed to stress corrosion cracking. Existing control mechanisms in place include operational procedures and Control Room competencies, modelling tools and field operations competencies.

(k) Increasing rotating plants with age will increase the non capital costs and stay in business capital expenditure.

(l) Other equipment reliability issues could impact on compressor availability.

(m) Additional facilities such as roads, airstrips, water amenities etc, will be required to support midline compressors, thereby increasing operating costs.

(n) Additional equipment such as motor vehicles etc. will be required to support midline compressor.

(o) Introduction of intermediate compressor units introduces issues associated with pressure, recycling, ESD and continuity of supply.

(p) If midline compressors are to be supported from current compressor stations, this may impact on the responsibility / downtime at each site.

(q) The ability of compressor manufacturer to supply the increased number of units on time.

7.4 The following risks were identified for the looping option:

(a) Environmental risks associated with the construction of a “duplicated” pipeline. Such risks include putting at risk endangered flora and fauna, impacts on wetlands, cultural heritage and native title issues.

(b) Industrial relations issues causing delays to the commissioning of the additional capacity.

(c) Availability of skilled labour given the current skills shortage.

(d) The proposed construction methodology for river crossings.

(e) The risks to security of existing supply as a result of greater number of hot-taps to connect new looping with existing pipework.

(f) Risks associated with hydro testing.

(g) Potential non compliance with environmental management plan required by Regulator.

(h) Changes in route selection from that on which the initial budget was based.

(i) Weather impacts (both heat and flooding) given that looping construction projects take longer and cover more diverse geographical areas than compression construction.

(j) Resultant risk of liquidated damages under existing contracts as a result of delays.

(k) Inability to secure sufficient resources due to competing pipeline projects being constructed at the same time.

(l) Landowner access issues.

(m) Pipeline licence variation approval delays.

(n) Late delivery of pipework to site.

7.5 In relation to the looping option, the effect of a delay in commencing the expansion program works could have resulted in adjusting the risk profile of the program and increasing DBP's risk by way of:

(a) Reducing the opportunity to obtain competitive market prices for the construction work and transfer of risk to the Contractor if sufficient time is not available; and

(b) Delaying the completion of the program works may incur penalties under the gas supply contracts.

7.6 The above risk analysis, combined with financial analysis, identified a number of risks that were common to both main options – ie looping and midline compression.

7.7 However, the operational risks associated with the midline compression option, including additional non capital costs and ongoing system reliability issues were major reasons why DBP decided to proceed with the 26" looping option.

8. PRUDENCY OF ACTUAL CAPITAL EXPENDITURE

Contracting strategy – Stage 4

8.1 Given the long term contracts it has with existing shippers, DBP has a commercial interest in keeping the cost of expanding the capacity of the DBNGP to a level that is consistent with achieving the lowest sustainable cost of providing gas transportation services.

8.2 In particular, DBP has contractual obligations to those shippers which have exercised their rights under clause 16 of the SSC to minimise costs.

8.3 These have been the principal reasons for the detailed examination of the costs of alternative expansion options and, in the case of the Stage 4 expansion program, why the particular option for Stage 4D was adopted by DBP.

8.4 Once the lowest sustainable cost expansion path has been identified, DBP must ensure that the expanded capacity is provided at – or below – the forecast cost and on time.

8.5 An appropriate contracting strategy was essential to achieving this outcome.

8.6 DELETED

8.7 There are a range of methods are available for securing the services of suppliers of equipment, and of engineering and technical services. At one end of the spectrum, that equipment or those services may be secured through fixed price contracts with suppliers. Somewhere along this spectrum is the method of engaging a supplier under a schedule of rates contract so that the contractor is better able to exclude contingencies from its pricing. At the other end of the spectrum, equipment, or engineering and technical services, may be secured through an alliance contract.

8.8 In alliance contracting, the party requiring equipment, or engineering and technical services, forms an alliance with the contractor, enabling both parties to work co-operatively to deliver required facilities of the desired quality at the best possible price. Alliance contracting delivers these outcomes through its facilitation of knowledge flow between the parties, and the provision of incentives for the sharing of knowledge.

8.9 The fundamental principles behind the alliance contract method include the following:

(a) The incorporation of a philosophy of “no disputes” and “no blame” so that when issues do arise, the parties are encouraged to work together to determine the best result for the project.

(b) A primary emphasis on business outcomes for all the parties.

(c) Clear understanding of individual and collective responsibilities.

(d) An equitable balance of risk and reward for all parties.

(e) Encouragement of openness and cooperation between the parties. This open book approach is important in setting the target price for an alliance contract.

(f) Encouragement to develop and apply innovative approaches and achieve continuous improvement.

(g) Access to and contribution of the expertise and skills of all parties.

(h) A commercial basis which offers the opportunity to achieve rewards commensurate with exceptional overall performance.

8.10 Under the alliance contract method, little or no risk is separately allocated to particular participants in an alliance. Instead, parties jointly accept the project risks up to a point, and work together to achieve the best outcome for a project. However, suppliers under alliance contracts are generally entitled to full recovery of the costs incurred during the alliance. Therefore their risk is effectively capped at their profit and overheads recoverable by them under the alliance.

8.11 There is no rigid contractual structure for an alliance project. The actual structure adopted will be influenced by the nature of the project, and the culture, corporate objectives and drivers of each of the alliance participants.

8.12 Some argue that the non-allocation of risk in an alliance contract favours the supplier, as they are the party who would usually bear the majority of risks under conventional forms of contracts, such as latent conditions, completion and defects. However, this position ignores the fact that risks usually borne solely by an owner under conventional forms of contracts are also shared between the participants under an alliance contract, such as legislative risk, cultural heritage and environmental risks.

8.13 Where these risks are encountered under a lump sum contract, they would usually result in a variation being directed by the owner, and the supplier being entitled to an adjustment of the lump sum price and time for completion.

8.14 In contrast, alliance contracts are more flexible. Where such issues are encountered under an alliance contract, the parties work together to overcome them.

8.15 Commercial arrangements under alliance contracts are often structured so that they require minimal adjustment during the course of the works. The risk/reward regime will usually only be altered in very limited situations. Similarly, there will usually be only limited grounds on which participants will be entitled to extensions of time or increased costs.

8.16 The issue of whether the contract price is too high or too low, always an issue with lump sum contracts (price is inevitably less than actual cost), remains an issue with alliance contracts. However, if an alliance contract has some form of target cost incentive, experience suggests that the ultimate price for the delivery of the service will be less than the co-operative estimate of that price (typically greater than actual cost), or the estimate of price arrived at by the buyer or the service supplier.

8.17 Alliance contracts provide beneficial cost and service related outcomes relative to lump sum contracts (even when those contracts are the results of tender process) for the following reasons:

(a) the supplier is able to mobilise quickly;

(b) the buyer of services (ie DBP) can exert a high level of control over any contract work carried out by the supplier (i.e. the alliance partner);

(c) the buyer can more readily change the delivery approach to accommodate project changes;

(d) alliance partners usually have a good understanding of projects and risks;

(e) there is the greatest likelihood of meeting tight deadlines;

(f) under lump sum or schedule of rates agreements, there is a steep learning curve for the supplier which will be factored into the pricing, resulting in an increased price for service provision;

(g) lump sum and schedule of rates agreements take time to formalise, and this may not be appropriate in circumstances where a new facility must be designed, and constructed or acquired, in a short period; and

(h) specification of the full scope of work for inclusion in a lump sum or schedule of rates contract takes time, and the buyer of the services bears the risk of later scope change.

8.18 DELETED

8.19 DELETED

8.20 The benefits of adopting an alliance contract strategy for at least the initial stages of the expansion program were reinforced during DBP's risk assessment of the Stage 4 project where it became apparent that the risk of delays to project completion was one of the biggest risks facing DBP's ability to meet its obligations to shippers under pre-existing access contracts.

8.21 The prime reason for this was that, at the time, there was at least one other pipeline construction project being undertaken at the same time as the Stage 4 project, therefore resulting in the two projects competing for the same resources such as construction personnel, equipment, camp and site support facilities etc. Therefore an important risk mitigation strategy was to lock in the required resources at an early stage to ensure availability in accordance with the contractual requirements.

8.22 The timely supply of pipe and securing of all required approvals is also considered important so that major aspects of the expansion project can be procured in order to ensure that there will be no delays.

8.23 In light of the above, DBP considered that the utilisation of the aforementioned alliance partners was prudent, particularly given they had been involved in the most recent major gas pipeline and facility construction projects carried out in Australia.

8.24 The alliance arrangements still required a significant part of the cost items to be the subject of a tender process. DBP envisaged most of the total cost of the project related to projects that had been the subject of competitive tender. [DELETED].

8.25 DELETED

8.26 Evaluation of tenders will involved assessment of each tender against the following criteria:

(a) Commercial terms and provisions;

(b) Technical conformance; and

(c) Value, including, but not limited to, the following:

(i) Financial elements (direct);

(ii) Life cycle costs analysis;

(iii) Product liability coverage;

(iv) Total supply chain management;

(v) Quality processes and systems (TQM and accreditation);

(vi) Customer focus and responsiveness;

(vii) Reliability of performance; and

(viii) Financial capability of company.

8.27 DELETED

8.28 As mentioned in the previous sections, in addition to the above requirements, it was a precondition to the drawdown of funds under the facility DBP entered into with its financiers to debt fund $350m of the capital costs of the forecast conforming capital expenditure, that an independent engineer jointly appointed by the financiers and DBP verify certain aspects of the expansion program, including:

(a) That each stage of the project is technically feasible having regard to good operating practice;

(b) That the proposed budget and timetable is prudent and reasonable;

(c) That appropriate levels of capacity will be created;

(d) That there is in place an appropriate mitigation strategy in respect of material issues and risks facing each stage of the project;

(e) That DBP's contracting strategy and the form and content of material construction contracts are appropriate.

8.29 DELTED

9. CAPITAL EXPENDITURE FORECAST IN 2005 COMPARED WITH ACTUAL EXPENDITURE

9.1 This section of the submission outlines the forecast of capital expenditure that was used as the basis for Access Arrangement submitted in 2005.

9.2 It should be noted that DBP is required to justify to shippers under the Standard Shipper Contract, the costs by reference to certain cost categories that are stipulated in the Standard Shipper Contracts.

9.3 This is not a usual means of reporting costs for DBP but at the time, it had not established accounting ledgers consistent with that in the Standard Shipper Contract

9.4 DBP ended up using a different ledger structure for the recording of actual expenditure. It is therefore difficult to reconcile the actual expenditure with the forecast submitted to the ERA in 2005.

9.5 DELETED

9.6 DELETED

9.7 DELETED

9.8 While the cost categories, as stated in the Standard Shipper Contract, are relatively self explanatory, the following information provides a further explanation of the nature of costs, items of plant and equipment and activities covered by each category:

9.9 Detailed design – in addition to the explanation, it includes design work for procurement, geotechnical surveys for looping, risk assessments, minor service contracts and other design work including:

(a) alignment sheets

(b) final route topographic survey and route optimisation due to environmental, cultural heritage and land owner issues;

(c) Identification of sections of the pipeline route that will require special construction methods and/or procedures including sections that are restricted in terms of available working space;

9.10 FEED – this includes costs relating to the commissioning of a FEED study, and internal costs associated with engaging the FEED consultant.

9.11 Material procurement – all costs associated with the purchase of materials and equipment, including compressor units and ancillaries, pipework and valves, control systems and instrumentation, and power supplies and cabling. It also includes:

(a) The tendering of the material purchase requisition packages, evaluation and award to the successful tenderer.

(b) Environmental assessments, approvals and surveys;

(c) Cultural heritage survey;

(d) Approvals by statutory authorities;

(e) Agreements with land owners and traditional landowners (through indigenous land use agreements);

(f) Placement of orders and commitment to critical subcontractors (eg camp, catering, etc);

(g) Establishment of a project site industrial agreement;

(h) Development of a construction execution plan and schedule and any other required management plans and procedures, including OHS, Quality Assurance;

(i) Development of quality welding and coating procedures;

9.12 Coating – this cost relates to the coating of the looping pipe.

9.13 Construction - all off-site and on-site fabrication and installation costs of the additional compressor station facilities, including set up and site costs, and construction costs, costs. This covers the following:

(a) Mobilisation of construction equipment and materials;

(b) Establishment of site facilities including camps, project site offices and maintenance and storage facilities and communication systems;

(c) Locate and set up sources for supply of water for the project;

(d) Identify access roads and restrictions relative to the same that will have to be addressed and or work that will have to be undertaken prior to the commencement of the delivery of pipe to the right of way; and

(e) Liaison and notification involving relevant land owners and or local authorities.

9.14 Transport – this includes the costs associated with transporting materials to site.

9.15 Pre-commissioning – DBP has not allocated any costs to this category as they are minor and hard to differentiate between commissioning costs. Instead, they have been included as part of the commissioning costs.

9.16 Commissioning and handover – these cover the costs associated in ensuring that the contracted capacity is able to be supplied at a level of reliability in accordance with the requirements of the shipper contract. They reflect about 2% of the total costs.

9.17 Consultants' fees – these cover 3rd party inspection fees for such individuals as the banks' advisers, the safety and technical regulator, legal advisers and other consultants.

9.18 Duty – duty is payable on the import of the line pipe. This covers this cost, which is approximately 5% of the cost of pipe.

9.19 Interest costs during construction – DBP has, for the purpose of this submission, included these costs under the construction cost category.

9.20 Departmental overheads – this category includes the following costs:

(a) Design review costs

(b) Regulatory compliance

(c) Project support costs

(d) The incremental costs of the DBP's GIS system, the labour costs of DBP's and its service providers corporate staff providing support. This includes heritage and land management support, engineering support etc.

9.21 Project Management – this includes on site and off site project management costs such as overall project management, risk assessment work, project safety management, construction support, topographical survey work and noise and vibration assessment work.

9.22 Insurance – this includes costs associated with obtaining project insurance for the expansion program. This includes brokers' fees, insurance premiums, stamp duty and other government charges. The types of policies envisaged are contract works (material damage), contract works (delay in start up), third party legal liability, Marine cargo, and project professional indemnity insurance. Liquidated Damages insurance is allowed for in operator's forecast non capital costs.

9.23 DELETED

Post Stage 4 Expansion Program capital expenditure

9.24 In relation to the expenditure that was forecast to be incurred following the commissioning of Stage 4, it was assumed at the time of the lodgement of the 2005 access arrangement that the only feasible means by which the pipeline could be expanded to provide additional capacity following the commissioning of Stage 4 was via looping of the pipeline. With the benefit of hindsight this has proven to be accurate.

9.25 Based on the approved option for Stage 4, the following configuration was estimated for the further expansion, based on DBP's demand forecasts at the time of the lodgement of the revised access arrangement in 2005.

Looping downstream of:	2008	2009	2010
Dampier	0 km	0 km	0 km
CS1	33 km	10 km	17 km
CS2	28 km	8 km	14 km
CS3	28 km	7 km	15 km
CS4	29 km	8 km	15 km
CS5	29 km	8 km	15 km
CS6	32 km	8 km	16 km
CS7	34 km	9 km	19 km
CS8	29 km	6 km	14 km
CS9	26 km	7 km	13 km
CS10	7 km	2 km	7 km
Total Loop	**275 km**	**73 km**	**145 km**

9.26 DBP assumed the same methodology for the design, procurement and construction of the additional looping for the years 2008 to 2010 in developing the configuration and costing estimates for these years as was adopted for the looping component required for the Stage 4 expansion project. It should be noted that the proposed looping program involves 26" looping and is configured to meet the forecast contracted capacity for the period.

9.27 If contracts could not be entered into, the additional capacity in these years would not be funded by DBP. This is consistent with the proposed expansions policy and the Standard Shipper Contracts entered into with shippers in 2004.

9.28 The costing therefore extrapolated the unit costs derived from the Stage 4 budget at the time.

Actual Capital Expenditure

9.29 The following table outlines the actual capital expenditure that has been incurred for expansion projects since 2005. As outlined above, it can not be directly reconciled against the detailed breakdown provided for in this section because the ledgers established to track actual expenditure did not match the line items in the forecast.

9.30 DELETED

	Actual					Forecast	
	2005	2006	2007	2008	2009	2010	2011
	1,618,370,000.00	1,619,056,445.80	1,675,828,341.74	2,063,022,634.40	2,680,782,266.09	2,708,621,252.63	3,395,281,659.96
Stage 4 Compression	-	52,701,923.50	153,622,428.67	-	9,534,363.08	-	-
Stage 4 Pipeline	-	-	229,784,242.94	-	-	-	-
Stage 4 Other	-	-	-	-	1,069,318.12	-	-
Stage 5A Compression	-	-	-	117,142,159.10	-	-	-
Stage 5A Pipeline	-	-	-	493,382,071.81	-	-	-
Stage 5A Other	-	-	-	1,437,548.43	-	14,000,000.00	-
Stage 5B Compression	-	-	-	-	-	155,000,000.00	-
Stage 5B Pipeline	-	-	-	-	-	450,000,000.00	-
Stage 5B Other	-	-	-	-	-	15,900,000.00	50,000,000.00

9.31 The following table is the comparison of all capital expenditure actually incurred during the period 2005 to 2010 (including the latest forecast of expenditure for 2010) with that which, in 2005, was forecast to be incurred for the same period.

9.32 The following is a legend applicable to the table:

(a) F2005 – the forecast capital expenditure for the year of 2005, as included in the 2005 Access Arrangement

(b) A2005 – the actual capital expenditure for the year of 2005, as indicated in the Proposed Revised AAI submitted in April 2010

(c) 2005Exp - the actual capital expenditure for expansions for the year of 2005, as indicated in the Proposed Revised AAI submitted in April 2010

(d) 2005 SIB - the actual stay in business related capital expenditure for the year of 2005, as indicated in the Proposed Revised AAI submitted in April 2010

Comparison of Capital Expenditure for the period 2005 to 2010 as forecast to the ERA compared with that actually made (comparison by Asset Class)

Year ending 31 December	F 2005	A 2005	2005 Exp	2005 SIB	F 2006	A 2006	2006 Exp	2006 SIB	F 2007	A 2007	2007 Exp	2007 SIB	F 2008	A 2008	2008 Exp	2008 SIB	F 2009	A 2009	2009 Exp	2009 SIB	F 2010	A 2010	2010 Exp	2010 SIB	F Total	A Total
Nominal $million (dollar values at end of year)																										
Pipeline	4.62	0.65	0	0.65	6.06	2.72	2.72		275.28	230.7	229.78	0.92	304.62	493.38	493.38	0	95.42	0.17		0.17	169.53	450	450		855.54	1777.62
Compression	3.79	-	0	0	72.53	50.83	49.98	0.85	127.02	154.35	153.62	0.73	44.93	118.81	117.14	1.67	0.47	21.72	9.53	12.19	0.72	171.7	155	16.7	249.47	517.41
Metering	1.16	-	0	0	1.3	0.05	0	0.05	0.17	-			0	-	0		0	0.08		0.08	0	0.05		0.05	2.62	0.18
Other depreciable assets	4.12	0.04		0.04	3.35	3.18		3.18	1.72	2.15		2.15	6.09	5.56	1.44	4.12	7.44	5.87	1.07	4.8	7.08	64.91	29.9	35.01	29.8	181.7
Total	13.69	0.69	0	0.69	83.24	56.78	52.7	4.08	404.19	387.19	383.4	3.8	355.64	617.76	611.96	5.79	103.33	27.84	10.6	17.24	177.34	686.66	634.9	51.76	1137.43	1776.91

10. STAGE 5A PRUDENCY OF DESIGN

10.1 Following is the high level summary of the Stage 5A expansion project:

	Actual		Forecast	
	2008	2009	2010	2011
Stage 5A Compression	117,142,159.10	-	-	-
Stage 5A Pipeline	493,382,071.81	-	-	-
Stage 5A Other	1,437,548.43	-	14,000,000.00	-
Total Expenditure	**611,961,779.34**	-	**14,000,000.00**	

Parameters Critical for Stage 5A Capacity and Investment

10.2 DBP proposed to expand the DBNGP to meet the needs of shippers and prospective shippers who have confirmed their capacity requirements, and who have entered into long term contracts for access to capacity.

10.3 In this section of this submission DBP sets out the principal assumptions it has made in developing its proposed expansion options.

10.4 These assumptions were principally in the form of assumed values for certain parameters which were critical for the design of Stage 5A, and for the total investment.

10.5 The parameters critical in the design of, and investment in, Stage 5A were:

(a) capacity to be provided;

(b) system reliability;

(c) compressor unit availability;

(d) gas composition;

(e) pipeline pressures;

(f) unit costs for pipeline looping;

(g) costs for compressor unit de-bottlenecking; and

(h) costs for certain other New Facilities.

10.6 The positions assumed by DBP for each of these parameters are discussed in the following paragraphs of this submission.

Capacity and reliability

10.7 Engineering design work for Stage 5A proceeded on the assumption of:

(a) a full haul Tranche 1 capacity requirement of 91 TJ/d;

(b) a requirement for an additional Pilbara part haul of 80 TJ/d to an offtake into the Goldfields Gas Pipeline to be located near Compressor Station 1; and

(c) an additional Mid-west part haul (to Eradu Road) of 6 TJ/day.

10.8 Tranche 1 Capacity is defined, in clause 3.2(b) of the Standard Shipper Contract, in terms of the probability with which it will be supplied.

10.9 In accordance with clause 3.2(b)(i) of the Standard Shipper Contract, the Tranche 1 Capacity in the DBNGP is the amount of capacity which lies between zero and the T1 cut-off.

10.10 The T1 cut-off is the amount of capacity at which the probability of supply for the next GJ of gas to be transported in the DBNGP to Kwinana Junction is 98% for each month of a gas year.

10.11 Historically, average ambient temperatures have been highest, and the thermal efficiency of gas turbines has been lowest, during January. Stage 5A was designed to provide 91 TJ/day of full haul capacity with 98% probability of supply in January average conditions.

10.12 DBP notes that by designing for Tranche 1 capacity, no specific allowance is, or can, be made for interruptible capacity, or for semi interruptible services in addition to those which are already the subject of existing transportation contracts.

10.13 DELETED

Compressor unit availability

10.14 A compressor unit availability of 98.3% has been assumed for the design of Stage 5A.

Gas composition and Gas Quality Specification

10.15 Gas composition is a critical factor in determining the capacity of the DBNGP: if composition changes, so does capacity. Hence, those stakeholders who determine gas composition also determine the capacity of the DBNGP, and thus have a major influence on the costs of expanding and operating the pipeline.

10.16 A pipeline service provider is usually able to set bounds on the composition of the gas to be transported through its pipeline by imposing a gas quality specification in gas transportation contracts. However, this does not determine the gas composition. It simply establishes the maximum and minimum capacities of the pipeline (all other things being equal). Given that a gas quality specification generally imposes quite broad ranges of values for certain components or attributes of the gas to be transported, the difference between the maximum and minimum capacities of the pipeline will generally be relatively large. This is the case for the DBNGP.

10.17 The key stakeholders that influence gas composition are gas producers, and shippers by way of their gas supply agreements with producers. A pipeline service provider has no role in the arrangements between producers and shippers, and is required to accept into its pipeline any gas that meets the quality specification set out in its gas transportation contracts. Gas producers and, to a lesser practical extent but to a still important contractual extent, shippers, therefore have a significant influence on pipeline capacity.

10.18 Existing Standard Shipper Contracts for the DBNGP at the time generally contained the following gas quality specification ("Operating Specification"):

Operating Specification

Component		Inlet Points	Outlet Points
Maximum carbon dioxide (mol %)		3.6	4.0
Maximum inert gases (mol %)		5.5	6.0
Minimum higher heating value (MJ/m^3)		37.3	37.3
Maximum higher heating value (MJ/m^3)		42.3	42.3
Minimum Wobbe Index		47.3	47.3
Maximum Wobbe Index		51.0	51.0
Maximum total sulphur (mg/m^3)	Unodorised Gas	10	10
	Odorised Gas	n/a	20
Maximum Hydrogen Sulphide (mg/m^3)		2	2
Maximum Oxygen (mol %)		0.2	0.2
Maximum Water (mg/m^3)		48	48
Hydrocarbon dewpoint over the pressure range 2.5 to 8.72 MPa absolute		Below 0^0C	Below 0^0C
Maximum radioactive components (Bq/m^3)		600	600
Minimum Extractable LPGs (t/TJ)[1]		n/a	n/a

1. Extractable LPG means LPG that can be extracted from Gas without causing the Gas to fail to comply with the Operating Specifications for Outlet Points.

10.19 However, the Revised DBNGP Access Arrangement, which was drafted and approved by the ERA, and which became effective on 30 December 2005, included in the terms and conditions for Reference Services, a gas quality specification which was broader than the Operating Specification. This broader specification ("AA Specification") is set out in the following table.

AA Specification

Component		Inlet Points and Outlet Points
Maximum carbon dioxide (mol %)		4.0
Maximum inert gases (mol %)		7.0
Minimum higher heating value (MJ/m^3)		37.0
Maximum higher heating value (MJ/m^3)		42.3
Minimum Wobbe Index		46.5
Maximum Wobbe Index		51.0
Maximum total sulphur (mg/m^3)	Unodorised gas	10
	Odorised Gas	20
Maximum Hydrogen Sulphide (mg/m^3)		2
Maximum Oxygen (mol %)		0.2
Maximum Water (mg/m^3)		48

AA Specification

Component	Inlet Points and Outlet Points
Hydrocarbon dewpoint over the pressure range 2.5 to 8.72 MPa absolute	Below 0 C
Maximum radioactive components (Bq/m^3)	600
Minimum extractable LPGs (t/TJ)	0

10.20 Generally, when designing for the expansion of the capacity of a pipeline, and when estimating the costs of expansion and pipeline operation, a pipeline service provider will need to make an assessment of the likely composition of the gas to be transported through the pipeline over the period the service provider expects (or is allowed) to recover investment in its pipeline.

10.21 The likely composition of the gas transported will be within the limits established by the gas quality specification in the pipeline service provider's gas transportation contracts. Within those limits, however, the likely composition of the gas to be transported is matter for gas producers and their customers.

Historical basis for determining capacity of DBNGP

10.22 In the engineering design work to expand pipeline capacity, the prior – public and private – owners of the DBNGP made the assumption that the likely composition of the gas to be transported through the pipeline would be an average of the composition of the gas which was actually transported in the immediate past.

10.23 The assumption that the likely composition of the gas to be transported would be an average of the composition of the gas which was actually transported was fundamental to DBNGP capacity determination for the purposes of establishing the regulated access prices of:

(a) the access regime of the Gas Transmission Regulations 1994, the regime applied by the State prior to the Code coming into effect in Western Australia;

(b) the Access Arrangement drafted and approved by the ERA's predecessor, the Western Australian Independent Gas Pipelines Access Regulator ("ERA's predecessor"), in December 2003 ("prior Access Arrangement"); and

(c) the Revised DBNGP Access Arrangement drafted and approved by the ERA in December 2005.

10.24 Since 1994, the DBNGP had been designed on the assumption that the quality of the gas to be transported through the pipeline was an average of the quality of the gas which was actually transported in the immediate past, and access prices have been determined on the basis of the pipeline capacity determined using this assumption.

10.25 The assumption that the quality of the gas to be transported through the pipeline was an average of the quality of the gas which was actually transported in the immediate past was made – either implicitly or explicitly - by the ERA's predecessor, and by the ERA, for the purpose of establishing the Reference Tariffs of the prior Access Arrangement and the Revised DBNGP Access Arrangement. The ERA's predecessor and the ERA both proceeded from a view that shippers using the Reference Service would benefit from Reference Tariffs established on the basis of a level of pipeline capacity determined assuming an average of the quality of gas actually transported, and that DBP would have the opportunity of earning a revenue stream which recovers the efficient costs of providing that level of capacity. Both the economic and the commercial outcomes of access regulation under the Code were to follow from the assumption that the quality of all of the gas to be transported in the DBNGP in the future would be an average of the quality of the gas which was actually transported at the time of filing of the prior Access Arrangement and of the revisions to the DBNGP Access Arrangement.

10.26 The initial Capital Base was established by the ERA's predecessor having regard to levels of maximum and firm capacity determined assuming the average quality of gas actually delivered was as shown in the second column of the following table.

Gas quality for initial Capital Base determination

	Average actual assumed for prior AA[1]	Amendment 15 operating specification
Carbon dioxide (mole %)	2.5	Max. 4.0
Inert gases (mole %)	4.3	Max. 7.0
Higher heating value (MJ/m^3)	40.8	Min. 37.0
Wobbe Index	50.1	Min. 46.5

1. Epic Energy Report MMS007-99, *DBNGP Alternative Capacity Definition*, August 1999, a copy of which was provided to the then Regulator.

10.27 As part of their response, the previous owners provided the ERA's predecessor with a copy of the internal report (DBNGP Alternative Capacity Definition, August 1999) which documented the capacity calculation. Section 2 of that report set out design criteria and assumptions made for the purpose of capacity determination. It indicated that the average of the actual gas composition (upstream of Kwinana Junction) shown in the table above (in paragraph 10.26) had been assumed. Furthermore, the report clearly noted that "different gas quality would significantly impact on pipeline capacity". This warning, that the capacities reported were critically dependent on the assumptions which had been made, was repeated in the submission (Information Request 7: Firm Service Capacity, 3 October 2000) to which the report was an attachment.

10.28 In a subsequent submission responding to the June 2001 Draft Decision issued by the ERA's predecessor (Response DD 3: Capacity of the DBNGP, 5 October 2001), the previous owners of the DBNGP again noted that the capacity of the pipeline had been determined on the assumption that the quality of the gas to be transported would be an average of the quality of the gas which was actually transported, and that a change in that assumption would significantly impact on the capacity which could be made available for firm service.

10.29 That capacity had been determined on the assumption that the quality of the gas to be transported would be an average of the quality of the gas which was actually transported was again made clear to the ERA's predecessor in the previous owners' submission CDAP #9: Additional response #2 to Draft Decision Amendments (29 April 2003). CDAP #9 advised that, if that assumption were changed – in particular, if it were changed by reducing the Wobbe Index from its then the level of 49.9 – there would be a significant reduction in pipeline capacity.

Basis for determining capacity of DBNGP

10.30 As noted above, DBP continued to assume, for the purpose of pipeline capacity determination, that the quality of the gas to be transported would be the average quality of the gas which was actually transported. Although it made this assumption for its planning for the period 2005 to 2010, DBP also recognised the State's desire to allow a broadening of the quality of gas transported in the DBNGP at this time and acknowledged that this may be in its own commercial interest.

10.31 Accordingly, in January 2005, DBP proposed a broader gas quality specification in proposed revisions to the DBNGP Access Arrangement (being the "Operating Specification").

10.32 Although DBP proposed a broader specification, it continued to plan capacity expansion on the basis of an average of the quality of the gas actually received into the pipeline. DBP's expectation was that, with the removal of the minimum LPG requirement, and a broadening of other components of the specification, the quality of the gas transported in the DBNGP would shift to the outer envelope of the new specification as existing producers adjusted their operations in response, and as new producers entered the market.

10.33 As the quality of gas transported in the DBNGP gradually changed over an extended period, DBP expected to offset the associated reduction in the capacity of the pipeline by compensating capacity expansions during this period. The capital costs of these compensating expansions would be included in the pipeline's Capital Base, and thereby recovered, at least in part, from shippers paying the Reference Tariff.

10.34 Were there to be, at any time, a "step change" in the quality of the gas actually transported, rather than the gradual change which was assumed, DBP would consider either making an application under the then section 8.21 of the Code or initiating changes to the DBNGP Access Arrangement between reviews (which is now allowed in accordance with Rule 65 of the NGR). This would allow the previously unanticipated costs of the capacity expansion required to compensate for the step change in quality to be recovered through the Reference Tariff.

10.35 DELETED

10.36 DELETED

A change in approach to the gas composition assumption is required for future expansions of the DBNGP

10.37 DBP considered that it was prudent for it to reassess its approach to the setting of the gas composition assumption to be used in the planning of future expansions of the DBNGP.

10.38 The key imperatives for DBP in reassessing its approach were:

(a) the decline in HHV and Wobbe Index, and greater variability in gas composition generally, experienced since July 2005 is impacting on DBNGP capacity and DBP's ability to meet existing contractual commitments;

(b) pressure from gas producers and the ERA to widen the gas quality specification to make the DBNGP accessible to a greater range of potential gas field developments;

(c) Standard Shipper Contract provisions which allow shippers to propose the delivery of lower quality gas than the contractual specification, subject to DBP receiving adequate compensation;

(d) demand from shippers and prospective shippers for significant new capacity (Stage 5A) for delivery between mid 2007 and early 2009;

(e) the need for DBP to be confident that the Stage 5A expansion project will be viable and will meet the reasonable requirements of shippers over the long term;

(f) DBP's desire to ensure adequate capital investment to meet contractual obligations without over-investing;

(g) a need to obtain a long term commitment from the ERA for an appropriate gas specification for use in designing DBNGP facilities, Reference Services and Reference Tariffs – and for the costs associated with Stage 5A; and

(h) a need to develop a compensation package (as envisaged by Clause 7.14 of the Standard Shipper Contracts) if a material broadening of gas quality were generally anticipated by industry stakeholders.

The Kimber Consultants Report

10.39 To facilitate the reassessment of its approach, DBP commissioned, from an independent consultant, a study of gas composition assumptions which might be made for the planning of future pipeline expansions. MJ Kimber & Associates Pty Ltd ("Kimber Consultants") was commissioned to prepare a report on an appropriate gas composition assumption for use in the determination of DBNGP capacity, and the levels of services which might be provided using the pipeline.

10.40 Kimber Consultants was to:

(a) conduct discussions with gas producers and prospective producers to obtain their views on gas quality projections for their respective fields, production capabilities, the likely sequencing of field development, and their ability to modify gas quality through processing, in order to provide a forecast of gas quality trends for up to 20 years;

(b) conduct discussions with shippers and the ERA (including ERA consultant, PB Associates) on their views on gas composition and future demand in order to provide a forecast of required gas quality trends;

(c) in conjunction with the DBNGP asset manager, Alinta Asset Management, examine historic gas quality trends, and consider the influence of short term variability on service reliability;

(d) assist Alinta Asset Management in the development of a modelling tool that can be used to predict the most appropriate gas composition;

(e) prepare a report that presents the findings suitable for issue to the key participants, DBP's banks and owners;

(f) review submissions to the ERA, and the reports of PB Associates on matters associated with the gas quality;

(g) hold discussions with all gas producers, Shippers and the ERA to develop a long term view on movements in gas quality at each of the DBNGP receipt points; and

(h) prepare a report which addressed:

(i) The range of circumstances which can potentially impact on the gas quality to be transported by the DBNGP in the long term – and hence on capacity and service reliability;

(ii) in aggregated form if necessary, the information provided and views expressed by particular stakeholders or stakeholder groups; and

(iii) the supporting arguments for recommending a particular gas specification as the most appropriate basis for the design of Stage 5 and future expansions.

10.41 The scope of the work was limited to the technical issues associated with reaching a resolution on gas composition.

10.42 A copy of the report prepared by Kimber Consultants ("Kimber Consultants Report") is attached to this submission as ATTACHMENT 3

10.43 The Kimber Consultants Report identified three gas composition assumptions which could be used for the design of the Stage 5 expansion (which implicitly requires a review of the existing pipeline configuration), and for estimation of the capital and operating costs that will, in turn, determine the gas transportation tariffs applicable after expansion. The three gas composition assumptions were:

(a) Very conservative: the lowest quality allowable is the AA Specification ("Very Conservative Composition"). In this case, shippers would pay a tariff higher than would be the case under either of the following composition assumptions for capacity certainty. Adoption the Very Conservative Composition should ensure that the capacity of the DBNGP will not be reduced below contracted capacity as a result of changes in gas composition within the AA Specification, and that DBP is able to meet all contractual obligations to shippers so long as the gas delivered to DBNGP inlet points meets the AA Specification.

(b) Conservative: pipeline design would use the lower end of the range of most likely gas composition. The specific composition to be assumed was derived from predictions of gas composition provided to Kimber Consultants, on a confidential basis, by the gas producers. This gas composition was referred to in the Kimber Consultants Report as the "Recommended Design Composition", and had a HHV of 37.7 MJ/m3 and a Wobbe Index of 47.9 MJ/m3. Gas of the Recommended Design Composition would be within, by a small margin, the lowest quality allowable under the AA Specification. If the Recommended Design Composition were assumed for pipeline planning, there would be some risk that contracted capacity would not be available on any day when gas delivered into the DBNGP was not of the Recommended Design Composition, even though it was within the AA Specification. Shippers would logically be required to manage this risk through accepting a greater level of Permissible Interruption than currently provided under the Standard Shipper Contract T1 Service.

(c) Median: pipeline design would use the "Median Gas Composition", where this composition was established by reference to predictions of gas composition provided to Kimber Consultants, on a confidential basis, by the gas producers. Gas of the median composition would contain around 0.85 tonnes/TJ of LPGs, and have a higher heating value of 38.7 MJ/m3 and a Wobbe Index of 48.6 MJ/m3. If the Median Gas Composition were assumed for pipeline planning, DBP could not guarantee to provide its contracted capacities, and could not take any responsibility for capacity shortfalls when (actual) gas composition fell below the Median Gas Composition. By accepting greater uncertainty in the capacity they could access, shippers would receive a lower gas transportation tariff.

10.44 The values for the key elements of the three gas composition assumptions are set out in the following tables:

Very Conservative Composition

Component	Mol %
Methane	87.850
Ethane	5.756
Propane	0.000
Iso-Butane	0.000
N-Butane	0.000
Iso-Pentane	0.000
N-Pentane	0.000
Hexane	0.000
Heptane	0.000
Octane	0.000
N_2	2.394
CO_2	4.000
Total	100.000
Derived Values	
HHV (MJ/m^3)	37.0
WI (MJ/m^3)	46.5
LPG (t/TJ)	0
Inerts (%)	6.39%

Recommended Design Composition

Component	Mol %
Methane	88.396
Ethane	6.554
Propane	0.000
Iso-Butane	0.000
N-Butane	0.000
Iso-Pentane	0.000
N-Pentane	0.000
Hexane	0.000
Heptane	0.000
Octane	0.000
N2	3.190
CO2	1.860
Total	100.000
Derived Values	
HHV (MJ/m^3)	37.734
WI (MJ/m^3)	47.940
LPG (t/TJ) Inerts (%)	0.00 5.05%

Median Gas Composition

Component	Mol %
Methane	88.39
Ethane	5.52
Propane	1.22
Iso-Butane	0.11
N-Butane	0.19
Iso-Pentane	0.06
N-Pentane	0.02
Hexane	0.01
Heptane	0.00
Octane	0.00
N2	1.95
CO2	2.53
Total	100.00
Derived Values	
HHV (MJ/kg)	49.95
SG	0.63
HHV (MJ/m^3)	38.70
Wobbe (MJ/m^3)	48.61
LPG (t/TJ)	0.85
Inerts (%)	4.5%
CO2 (%)	2.5%

10.45 The Kimber Consultants Report recommended a gas composition – the Recommended Design Composition – for the design of the Stage 5A expansion of the DBNGP. In making this recommendation, Kimber Consultants noted that:

(a) the Recommended Design Composition represented the most realistic composition available to the DBNGP while recognising contractual obligations related to the Wesfarmers LPG plant;

(b) the Recommended Design Composition provided for a high, but not absolute, level of certainty that the contracted firm capacity would be available to shippers;

(c) the Recommended Design Composition would ensure that DBP could meet its contractual commitments for firm service to shippers at the expected gas composition, but did not ensure DBP could meet its contractual commitments for any service to shippers if the gas delivered into the DBNGP were of the lowest quality permitted under the AA Specification;

(d) if the Recommended Design Composition were adopted, shippers would have to understand that their firm capacity entitlements would be reduced if the heating value of the gas presented for transportation in the DBNGP were less than that of the Recommended Design Composition, namely, 37.7 MJ/m3;

(e) new and amended gas transportation contracts would have to be drawn up to ensure that the management of risk in the supply chain (both financial and physical) were vested in those businesses best positioned to manage the risk;

(f) if either the Very Conservative Composition or the Recommended Design Composition were adopted for the design of the Stage 5 expansion, shippers would need to understand that the cost of transportation would be higher than would be the case if the Median Gas Composition were assumed, but that they would be assured that their contracted capacities would be available when required unless gas producers allowed the heating value to fall below the agreed contractual lower limit; and

(g) at present, all gas quality risk that affects current pipeline capacity5 rests with DBP under the Standard Shipper Contracts, with the mitigation being “negotiation or compensation” under clause 7.14.

DBP’s gas composition assumption

10.46 Notwithstanding the recommendation from the Kimber Consultants Report, DBP assumed the Very Conservative Composition for its planning of Stage 5A and future expansions of the DBNGP.

10.47 DBP did so for the following reasons:

(a) The data provided to Kimber Consultants, which can reasonably be assumed to have been the best available data in the market at the time, were speculative beyond five years. DBP is, however, required to contract for capacity and recover its investments over much longer periods. Under the terms of the Standard Shipper Contract, DBP must contract for T1 capacity for a minimum term of 15 years, and under the way in which the National Gas Access (WA) Act 2009 is applied, major investment recovery via the Reference Tariff is over 30 to 70 years.

[5] In this context “current pipeline capacity” refers to the capacity of the DBNGP calculated using previous design criteria which included a heating value of the gas of 39.3 MJ/m^3.

(b) Based on views expressed in the Kimber Consultants Report, and its own experience in operating the DBNGP, DBP expects that the composition of gas supplied into the pipeline will fall outside the Recommended Design Composition on occasions as changes are made to gas production operations, and as faults occur in production facilities. Accordingly, there will be occasions when the capacity of the DBNGP will fall below contracted capacity at the Recommended Design Composition.

(c) Experience over the preceding 12 months demonstrated that:

(i) the composition of gas in the DBNGP has changed dramatically for reasons which extend beyond the removal of the minimum LPG requirement. In particular, the levels of inerts in the gas have been higher than at any time in the past and have, on occasions, exceeded the maximum allowable levels at certain inlet points;

(ii) fluctuations in the quality of the gas became more volatile;

(iii) gas composition has greater variability than has been assumed by certain producers for this period; and

(iv) some of the components and attributes of some gas supplied for receipt into the DBNGP have exceeded the corresponding outer limits of the Operating Specification.

(d) There is a significant capability within the existing operations of gas producers to manipulate the quality of the gas to be supplied into the DBNGP.

(e) The AA Specification included by the ERA in the Revised DBNGP Access Arrangement was, at the time, broader than the Operating Specification in the Standard Shipper Contracts, thereby facilitating gas of a composition broader than that which could reasonably be expected to be the case if the specification in the Access Arrangement had been the Operating Specification.

(f) There was, at the time, a reasonable risk that the gas quality specification in the Revised DBNGP Access Arrangement may be broadened further than the AA Specification in future revisions to the Access Arrangement, given that gas from those new fields which are likely to be brought into commercial operation in the foreseeable future is not likely to meet the AA Specification.

(g) DBP's ability to recover the investment it makes in future expansions of the DBNGP's capacity will need to be assessed over the expected life of the asset (as established in the Access Arrangement). The existing Standard Shipper Contracts are scheduled to expire in 2019, thereby giving rise to Spare T1 Capacity at that point in time, which Capacity could be accessed by way of the Reference Service. If the composition of the gas at that point in time is broader than that to be assumed by DBP in configuring the Stage 5 expansion, and the composition of the gas that is supplied for receipt into the DBNGP is broader than the Operating Specification, DBP will be deprived of the opportunity to recover its investment.

(h) The existing Standard Shipper Contracts at the time provided (and still do provide) for reversion of the contractual tariffs to the nearest equivalent Reference Tariff in 2016. Given that the total revenue in the current Access Arrangement only assumes costs associated with gas of a composition that is "narrower" than the composition of gas currently being transported in the pipeline, if the composition of the gas in 2016 is broader than that now assumed by DBP in configuring the Stage 5 expansion, the Reference Tariff at that time will not be sufficiently high to recover the investment.

(i) The terms and conditions of the Reference Service of the Revised DBNGP Access Arrangement do not enable DBP to provide a volume of services sufficient for it to recover the Total Revenue set by the ERA.

(j) The fact that the ERA had, at the time, concluded in its assessment of the revisions to the DBNGP Access Arrangement that there is minimal difference in capacity between a pipeline that is designed assuming gas of a composition corresponding to the outer limit of the Operating Specification, and a pipeline designed assuming gas of a composition corresponding to the outer limit of the AA Specification.

(k) If DBP chooses to assume for pipeline design gas of a quality higher than the gas that is actually shipped, then the capacity of the DBNGP will be insufficient to meet DBP's contractual obligations. In addition to its being exposed to the risk of less than total cost recovery, DBP will incur penalties – a double loss. Moreover, DBP could be exposed to indirect damages if its failure to design for the Very Conservative Composition were considered to be a wilful default.

(l) If shippers continue to require high reliability in their gas supply arrangements, DBP can only meet their requirements by assuming the Very Conservative Composition for the design of Stage 5A.

Gas composition since July 2005

10.48 The change in gas composition during 2005, and the corresponding reduction in gas quality, were faster and more acute than was anticipated at the time the current owners acquired the DBNGP, and for the purposes of planning and costing the Stage 4 expansion. Average HHV (and hence maximum capacity) has reduced by approximately 5% since July 2005. [DELETED]

10.49 DELETED

10.50 Aside from these exceptional quality excursions, although the reduction in gas quality has generally been to levels that fall within the limits of the Operating Specification, the quality of gas supplied into the DBNGP appears to be continuing to decline.

10.51 DBP notes that the composition of gas supplied for receipt into the DBNGP at Dampier for the period since July 2005 was for some time broader than the composition predicted by the North West Shelf gas producers for this period, and advised to the ERA as part of the ERA's assessment of proposed revisions to the DBNGP Access Arrangement[6]. At the time of the investment, this called into question the reliability of the forecasts provided by the producers, and of the conclusions drawn from them by the ERA.

Impact of changes in gas quality

10.52 The changes in the gas composition since June 2005, at the time had the following adverse impacts on DBP:

(a) DBP experienced problems in supplying all contracted capacities within the requirements of its Standard Shipper Contracts;

(b) the transportation of a larger volumes of lower quality gas (to deliver the same amounts of energy) increased DBNGP operating costs;

[6] See Attachment A to the report prepared by PB Associates, "Evaluation of the Impact of a Broader Gas Specification", dated September 2005.

(c) given that the reduction in gas quality had been greater and faster than was previously assumed, the Stage 5A expansion project needed to include a component through which capacity that had been lost up to that point in time was reinstated; and

(d) in planning for Stage 5A and subsequent expansions, consideration must now be given to the likelihood of further changes in gas quality, and further reductions in pipeline capacity which will have to be reinstated.

Impact of the ERA's position on gas quality

10.53 At the time it was reasonable to assume that the ERA's final decision on the gas quality specification for the Revised DBNGP Access Arrangement was likely to have the following adverse impacts on DBP over and above those outlined above.

(a) The difference between the AA Specification and the Operating Specification of the Standard Shipper Contracts provided gas producers with negotiating leverage to reduce the quality of gas supplied under existing and new gas supply agreements.

(b) In drafting and approving its own revisions to the DBNGP Access Arrangement, the ERA has required part haul, back haul and spot capacity services as Reference Services. Were any of these services to be provided at the AA Specification, it is likely that DBP would breach either the capacity or gas quality obligations it has under the existing Standard Shipper Contracts. These outcomes are likely because there is currently spare capacity for at least part haul and spot capacity services.

(c) In the longer term – after the current full haul capacity shortfall had been made up as part of Stage 5A, and until 2019 when most of the Standard Shipper Contracts are expected to terminate – the likelihood of breaching contracts will depend on the magnitude and quality of future gas supplies, and on the gas quality specification applicable at the time. The ERA indicated at the time that it may seek to further widen the quality specification in the DBNGP Access Arrangement when it considers future revisions.

(d) After 2019, shippers previously transporting gas under Standard Shipper Contracts will be free to switch to access contracts established under the access regime that then exists. These access contracts will apply the then current gas quality specification for Reference Services. This creates long term uncertainty about the parameters to be adopted in the planning of pipeline expansions. To the extent that DBP must, over time, respond to multiple changes in the gas quality specification for the DBNGP; future expansion costs are likely to be significantly higher than they might otherwise have been.

(e) The Reference Tariff of the Revised DBNGP Access Arrangement at the time had not been set having regard to the composition of gas that has actually been transported in the pipeline since July 2005. Neither its level nor its structure could therefore, at the time, be assumed to be efficient.

10.54 DELETED

10.55 DELETED

Pipeline pressures

10.56 A maximum allowable operating pressure (“MAOP”) of 8,480 kPa has been assumed for the design of Stage 5A.

10.57 DBP held a good understanding of the implication of an increase in the MAOP to 9,300 kPa for the main line between Dampier and Kwinana Junction. DBP’s investigations had shown that the increase in MAOP could be implemented with relatively minor modifications to existing compression and metering facilities, and would provide an additional 40 TJ/d of full haul capacity. However, changes in Australian Standard 2885.1 would be required for DBP’s approach to be compliant. Those changes at the time were opposed by the Western Australian and Queensland technical regulators, the standard had not changed and therefore DBP was not in a position to consider expansion that incorporate into the design an increase in MAOP.

10.58 In addition to the pipeline licence restrictions placed on the MAOP of the DBNGP, DBP has certain contractual obligations to shippers which require delivery of gas at certain outlet points to meet certain pressures.

10.59 Within this context, the following specific assumptions about pressures have been made for the design of Stage 5A:

Location	Pressure
NWSG – Dampier receipt point	8,480 kPa
Apache	Line Pressure
Griffin	Line Pressure
Kwinana Junction upstream of Wesfarmers LPG plant	5,150 kPa
Kwinana Junction downstream of Wesfarmers LPG plant	4,630 kPa
Kwinana West (Cockburn delivery)	3,550 kPa
Pinjarra Cogeneration	3,300 kPa
Wagerup Cogeneration	3,300 kPa
South West Cogeneration	3,300 kPa

Budget

10.60 DELETED

10.61 DELETED

10.62 In developing the Budget for stage 5A, DBP had greater confidence in the accuracy of the forecasts simply due to the fact that the Stage 4 expansion project was being completed and there was a very similar configuration being proposed in so far as the looping aspect of Stage 4 was concerned.

10.63 It was proposed to use similar contracting methodologies to those used in stage 4 and to improve on the systems developed for stage 4. There were other learnings from the Stage 4 project that were used in developing the Stage 5A budget.

10.64 In addition, DBP and the project manager, while still needing to deliver a project in relatively quick time (having regard to the timing requirements of the shipper contract).

11. ANALYSIS OF STAGE 5A OPTIONS

Expansion options

11.1 An efficient Stage 5A expansion of the DBNGP builds on, rather than makes redundant, the infrastructure that was provided by Stage 4, and which had been provided by earlier expansion projects. A key element of the design for Stage 4 was the upgrading and reinforcement of compression for efficient operation with the northern and southern looping projects which were part of that stage of expansion.

11.2 With the completion of Stage 4 (and without an increase in the MAOP of the DBNGP), options for further efficient capacity expansion through the addition of compression at existing compressor stations were exhausted (although there was scope for a further small increase in capacity through modifications to existing compressor units).

11.3 Capacity expansion by the installation of additional compressors at new locations intermediate between existing compressor stations was considered, but rejected. This "mid-line compression" option required both additional compression and looping. The reduction in loop length made possible by mid-line compression was not, however, sufficient to offset the capital cost of the additional compression. Additional compression would also result in higher operating – fuel and maintenance – costs than would be the case under other possible expansion options.

11.4 Significant additional compression power will not enhance the DBNGP's capability to provide the full haul (T1) transportation service and, in these circumstances, the capacity of the Stage 5A expansion must be provided by further pipeline looping.

11.5 Two principal options were identified as ways of providing the Stage 5A capacity requirement within the time required by the provisions of the relevant Standard Shipper Contracts. The first of these options – Option 5A(1) – requires further looping downstream of Dampier, and downstream of each compressor station (including CS10), plus turbine up-rating and compressor restaging to increase the power available from the existing compression facilities.

11.6 The DBNGP had a single 10 MW compressor unit at CS1. A second 10 MW was installed as part of the Stage 4 expansion augmenting the power of the first unit. The pressure and capacity that could be provided downstream and, in particular, the pressure and capacity that could be provided for gas deliveries into a new offtake into the Goldfields Gas Pipeline, would, however, remain constrained, primarily because of the pressure differential between the two transmission pipelines. A second option for Stage 5A – Option 5(A)(2) – therefore contemplated a third 10 MW unit at CS1 with a reduced requirement for looping downstream of Dampier, plus turbine up-rating and compressor restaging to increase the power available from the existing compression facilities.

11.7 Each of the two options for expansion is described in the paragraphs which follow.

Option 5A(1) – Looping plus turbine up-rating and compressor restaging

11.8 Option 5A(1) comprises the following:

(a) 623 km of looping with 26 inches diameter pipe between Dampier and Kwinana Junction;

(b) 15 km of looping with 26 inches diameter pipe between CS10 and MLV 157 (the pipeline end);

(c) up-rating of Solar Mars 90 compressor units at CS1/1 and CS8/1 to Mars 100;

(d) up-rating of Solar Centaur units at CS10/1 and CS10/2;

(e) compressor station "de-bottlenecking":

(i) restaging of compressor units at CS1/1, CS2/2, CS3/1, CS4/2, CS5/1, CS5/2, CS6/2, CS7/2, CS8/1, CS8/2 and CS9/1;

(ii) restaging of compressor units at CS10/1 and CS10/2;

(iii) replacement of scrubbers at CS1, CS5 and CS8;

(iv) modification of aftercoolers at CS1, CS2, CS3, CS4, CS5, CS7 and CS8; and

(v) replacement of gas engine alternators at CS1, CS2, CS4, CS6, CS7, CS8 and CS9.

11.9 Although the capacity for Stage 5A is to be provided primarily by looping, a small increment can be obtained by up-rating the existing compressor units at CS1/1 and CS8/1, increasing the available power from these units by about 1.3 MW. The additional power can, however, only be accessed if the control systems on the compressor units are also upgraded.

11.10 At completion of Stage 4, gas flows were expected to rise to the maximum levels that can be sustained with existing equipment and facilities at many compressor stations. That equipment, and those facilities, must be upgraded to remove the capacity constraints they would otherwise impose with the higher gas flows expected following completion of Stage 5A. In particular:

(a) one or more compressor units at each compressor station will require restaging;

(b) larger scrubbers will be required at three stations;

(c) aftercoolers at CS1, CS2, CS3, CS4, CS5, CS7 and CS8 will require modifications; and

(d) increased electric power generation capability will be required at CS1, CS2, CS4, CS6, CS7, CS8 and CS9, and is to be provided by replacing existing gas engine alternators.

11.11 DBP notes that the Stage 5A capacity requirement could be provided without changing from series to parallel compressor unit operation, and without installing active cooling on compressor units.

11.12 DELETED

Option 5A(2) – Looping, plus turbine up-rating and compressor restaging, plus an additional 10 MW unit at CS1

11.13 Option 5A(2) comprises:

(a) 559 km of looping with 26 inches diameter pipe between Dampier and Kwinana Junction;

(b) 15 km of looping with 26 inches diameter pipe between CS10 and MLV 157 (the pipeline end);

(c) installation of one new 10 MW compressor unit at CS1, and parallel pipework;

(d) up-rating of Solar Mars 90 compressor units at CS1/1 and CS8/1 to Mars 100;

(e) up-rating of Solar Centaur units at CS10/1 and CS10/2;

(f) compressor station “de-bottlenecking”:

(i) restaging of compressor units at CS1/1, CS2/2, CS3/1, CS4/2, CS5/1, CS5/2, CS6/2, CS7/2, CS8/1, CS8/2 and CS9/1;

(ii) restaging of compressor units at CS10/1 and CS10/2;

(iii) replacement of scrubbers at CS1, CS5 and CS8;

(iv) modification of aftercoolers at CS1, CS2, CS3, CS4, CS5, CS7 and CS8; and

(v) replacement of gas engine alternators at CS1, CS2, CS4, CS6, CS7, CS8 and CS9.

11.14 Option 5A(2) is similar in scope to Option 5A(1), but incorporates a new 10 MW compressor unit at CS1 to ensure the required gas flow and pressure maintenance downstream of the station. With the introduction of the new unit, the station would be converted from series to parallel operation: the two existing compressor units (which are currently configured for series operation), would be reconfigured for operation in parallel, and in parallel with the new unit. CS1 would become the first DBNGP compressor station with the parallel unit configuration which has previously been identified as being necessary to accommodate gas flows significantly higher than those expected at the completion of Stage 4.

11.15 Through compressor unit restaging, parallel unit operation, and the removal of station bottlenecks, DBP expected to be able to utilize to the fullest extent possible, existing equipment and facilities in its responding to the demand for gas transportation supporting Stage 5A, and in its responding to subsequent increases in the demand for pipeline capacity.

11.16 DELETED

11.17 DELETED

Project management fee

11.18 In accordance with the terms of the OSA under which the project manager provided services to DBP, the 3% project management fee applies not only to overheads. It also applies to all other components of project cost. Thus the forecast investment for Option 5A(1) includes a total WestNet project management fee of $22.142 million ($0.720 million for overhead services, and $21.422 million for all other construction services). Similarly, the forecast investment for Option 5A(2) included a total WestNet project management fee of $21.069 million ($0.720 million for overhead services, and $20.349 million for all other construction services).

11.19 Detailed justification of the project management fee is provided in Section 16

Contingency

11.20 The forecast investment for Options 5A(1) and 5A(2) includes, in each case, a contingent amount in relation to line pipe and compressor station costs. This contingency is set at 5% of currently identified costs.

11.21 DBP notes that the contingency is an integral part of its project costing. It is not an amount added arbitrarily to a current best estimate of project costs.

11.22 As project planning and design for a major construction project proceed, estimates are made of identifiable costs, and these estimates are "refined" or "firmed up" as materials and services requirements become better specified, and as contractual arrangements are concluded with materials and services suppliers. Even once supply contracts have been concluded, costs may remain uncertain because work must be undertaken as part of the project scope of work to identify subsequent materials requirements and to estimate what the costs of those materials might be. (For example, the Stage 5A scope of work included DBP working with Solar Turbines to specify the requirements for compressor unit restaging at each of the DBNGP compressor stations. Until this work is carried out, only very approximate figures could be given for the restaging work required, and for the costs of that work.)

11.23 Furthermore, as a project is undertaken costs which were not previously identified may have to be incurred. (For example, in the context of Stage 5A the specifications available for the existing DBNGP SCADA system may indicate that it can be integrated with the new SCADA facilities required for the loop line. However, when the new SCADA facilities are installed they may overload the existing system, requiring the unplanned upgrading of that existing system.)

11.24 Uncertainty in project costs may also arise from events which are outside the project manager's control. (For example, the Stage 5A construction schedule will make allowance for the suspension of work for an expected number of cyclones. If, however, the number of cyclones exceeds the number expected, additional costs would be incurred.)

11.25 In the planning of a major project (such as the Stage 5A expansion of the DBNGP), account will be taken of the effects of these sources of uncertainty on project costs. Once a detailed schedule of activities has been prepared, engineering staff will, on the basis of their collective experience, assign ranges to uncertain quantities, costs and event, and assign probability distributions to those ranges, allowing the Monte Carlo simulation of the distribution of total project costs. From this distribution, an assessment is made of a reasonable allowance for uncertainty. That allowance is then used to estimate the project contingency.

11.26 The amount of the contingency is the result of a rigorous examination and assessment of each key project uncertainty, and it becomes an integral component of project cost. When a specific uncertainty is (or is about to be) realized, any additional costs which must be incurred are provided for from the contingency.

11.27 DBP notes that the project management structure being established for Stage 5A (see paragraphs 11.40 to 11.47 of this submission) incorporates a strong internal control on the use of the project contingency. Use of the contingency requires the approval of both the asset owner (DBP) and the project manager (AAM). The project manager's use of the contingency to "correct" errors in project budgeting is unlikely to be approved by the asset owner, and any request by the asset owner for additional work outside the scope of the project is unlikely to be approved by the project manager.

Comparison and preferred option

11.28 DBP's assessment, over the life of the pipeline looping (assumed to be 70 years as in the Revised DBNGP Access Arrangement), of the average incremental costs expected under each of Options 5A(1) and 5A(2). In making this assessment, compressor units were assumed to have a life of 30 years (again, as in the Revised DBNGP Access Arrangement), and the additional compressor of Option 5A(2) has been assumed to be replaced at intervals of 30 years.

11.29 Although Option 5A(2) has a lower initial capital cost than Option 5A(1), its future capital and operating costs are expected to be higher. In consequence, the present value of the total (capital and operating) costs of Option 5A(2) exceeded the present value of the total costs of Option 5A(1) by approximately $19.0 million (real, December 2004 cash flows discounted at 7.24% pre-tax real).

11.30 DBP's assessment of the costs of Options 5A(1) and 5A(2) was made using system average fuel costs calculated assuming steady state conditions. The assumption of steady state is, however, not an accurate description of operating conditions at CS1 (the location of the additional compressor of Option 5A(2)), where pressure requirements are expected to vary considerably depending not only on gas flows into the Goldfields Gas Pipeline, but also on downstream flows. DBP expects that, in these circumstances, the increase in fuel costs resulting from the installation of the additional compressor at CS1 will be less than 50% of the increment determined assuming steady state conditions. In consequence, the present value of the costs of Options 5A(1) and 5A(2) will be approximately equal.

11.31 DBP's preferred option for Stage 5A was, therefore, Option 5A(2). This option was preferred for the following reasons:

(a) it can be designed, constructed and commissioned for the lowest capital cost;

(b) its total cost is not expected to be higher than the total cost of the alternative;

(c) it provides DBP with greater operational flexibility in maintaining pressure for gas delivery into the Goldfields Gas Pipeline;

(d) a third compressor at CS1, with parallel operation of the three units at the station, will be required when shipper commitments allow DBP to develop the additional capacity expected to support subsequent expansion of the DBNGP; and

(e) there is less risk to delays for commissioning the additional capacity than the alternative.

11.32 The issues of economies of scale and of scope were also important considerations to the decision on stage 5A. Economies of scope arise where fixed costs can be spread over a wider range of services. Expansion of the capacity of the DBNGP is not expected to widen the range of services which can be offered by DBP, and scope economies are of little or no relevance for the Stage 5A expansion.

11.33 Economies of scale are important in assessing pipeline expansion options. Both pipeline looping and the addition of compression have high initial set-up costs, and average costs which decline as additional capacity is provided.

11.34 DBP notes that additional compression adds discrete increments of capacity, and the increment of capacity that may be available from further compression of a pipeline may exceed the additional capacity to which shippers have committed. If capacity expansion is to be by compression, there may be economies of scale available by expanding the capacity of the pipeline beyond the immediate capacity requirement.

11.35 However, this is not the case for the DBNGP. Following the completion of Stage 4, there was limited scope for the provision of additional capacity by adding compression, and the capacity of Stage 5A had to be provided primarily by pipeline looping.

11.36 The issue for consideration was whether looping for Stage 5A should be designed to meet the capacity to which Shippers and Prospective Shippers have now committed, or whether, to exploit available scale economies, the looping should be designed to meet the capacity expected to be required over a longer period.

11.37 DBP designed the looping for Stage 5A to provide only the capacity to which Shippers and Prospective Shippers have now committed. It has done so because there is no obvious increment in capacity – beyond the amount to which Shippers and Prospective Shippers have committed – which should now be added to the DBNGP without creating undue risk to DBP's legitimate business interests. Unlike compression, which adds capacity in discrete increments, loop lengths can be adjusted to meet any specific capacity requirement (at least up to about 320 TJ/d, at which point the pipeline will be fully looped).

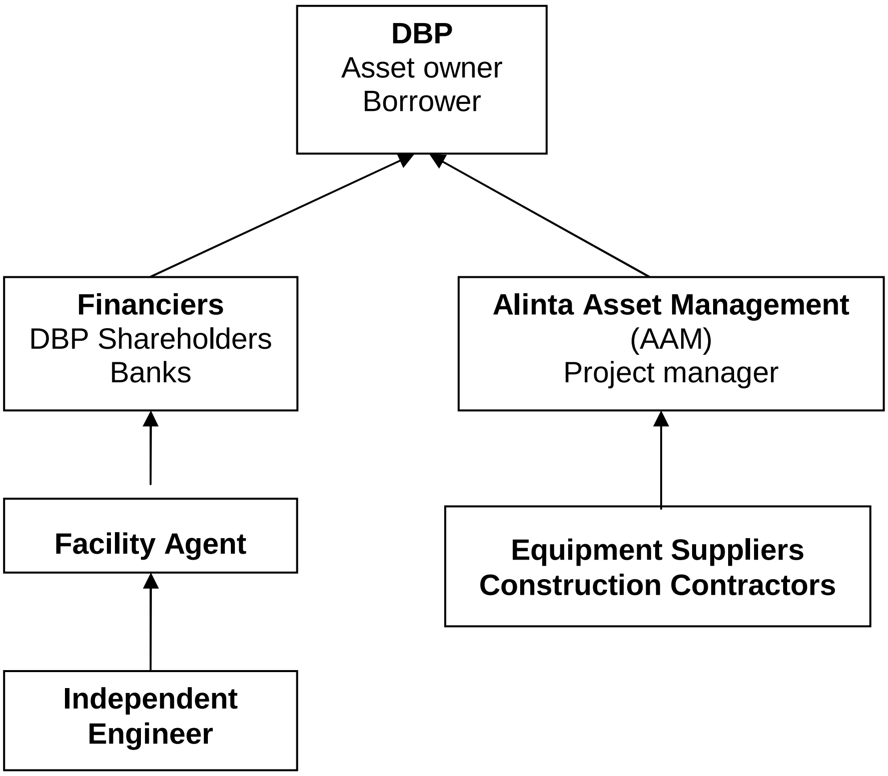
11.38 To ensure, in these circumstances, that the expansion of the DBNGP proceeds at the lowest sustainable cost, Stage 5A was progressed on the assumption that the shipper commitments to capacity which will allow DBP to proceed with Stage 5B (and possibly with Stage 5C) will be forthcoming within a timeframe which enables those further stages of expansion to make use of the supply chain and construction infrastructure to be created for Stage 5A.

11.39 Furthermore, DBP is proposed to undertake, as part of its providing the Stage 5A capacity requirement, turbine up-rating and compressor restaging which must be completed before there can be any further significant increase in the capacity of the DBNGP. As Stages 5B and 5C, and subsequent stages of expansion are committed to, DBP expects to expand by looping and by adding a third compressor unit (in parallel configuration) at each compressor station. All new looping, compressor plant and other equipment is to be rated for operation at pressures up to 10.2 MPa. This will allow, in the future, expansion by completion of the looping of the DBNGP, and the operation of a dual pipeline system with the looped line able to be operated at higher pressures than the existing DBNGP mainline. Over the longer term, this should ensure that expansion of the DBNGP is achieved at the lowest sustainable cost of delivering services.

Project organization and management

11.40 The Stage 5A expansion of the DBNGP was a major engineering project. The principal participants in the project are shown in the following diagram.

DBNGP Stage 5A expansion: project organisation



11.41 DBP, as asset owner:

(a) contracted the financiers, and was primarily responsible for the management of the financing arrangements;

(b) entered into all major construction contracts, in order to comply with the terms of the financing agreements;

(c) is the party to whom all licences and authorisations were issued;

(d) is responsible for all communications with government; and

(e) is responsible for all economic regulatory issues arising from the expansion program.

11.42 DELETED

11.43 DELETED

11.44 Alinta Asset Management ("AAM") had expertise in the project management of the construction and operation of gas transmission pipelines. Subject to the terms and conditions of the Operating Services Agreement ("OSA") it had at the time with DBP, AAM managed the Stage 5A expansion, ensuring that additional capacity was available when required by the shippers.

11.45 DELETED

11.46 The Project Director:

(a) had overall responsibility for project direction and progress against an approved workplan for Stage 5A (setting out the scope of the project, the budget, project timeframe, occupational health, safety and environmental issues, and client service requirements);

(b) directed the project team, and any other AAM activity required for project delivery;

(c) monitored and controlled performance against project key performance indicators;

(d) with DBP, negotiated procurement and construction contracts;

(e) developed and maintained project management reporting, and reports on trends, issues and productivity impediments to DBP and its Board on a timely basis;

(f) ensured that all DBP and Alinta corporate policies and procedures are implemented and followed.

11.47 The Project Director had the resources of:

(a) Project office:

(i) manages project schedule and processes;

(ii) manages project communications;

(iii) assists with the development of the detailed work plans for project work streams;

(iv) ensures timely resolution of work stream issues and risks;

(v) provides quality control;

(vi) provides a central repository for all project documentation;

(b) Gas modelling group:

(i) undertakes detailed hydraulic modelling of all capacity scenarios to ensure that the proposed work schedule will enable all commitments to shippers to be met;

(ii) provides input into project technical specifications;

(iii) liaises with party providing independent verification of modelling and/or Independent Engineer (as appropriate);

(iv) develop of detailed budget information for project;

(c) Project Manager - Pipeline Looping:

(i) manages pipe delivery from mills, pipe coating, and the transportation of pipe to site (ensuring suitable vessels, etc. are utilized to minimize risk of damage to pipe).

(ii) interfaces with EPCM contractor, and construction contractor regarding pipe installation; and

(iii) provides weekly report to Project Director;

(d) Project Manager – Compression:

(i) manages and co-ordinates delivery of compressor equipment from suppliers;

(ii) interfaces with EPCM contractor; and

(iii) provides weekly report to Project Director;

(e) Health, safety and environment group: ensures all aspects of the project comply with the safety case, and with environmental policy and cultural heritage policy;

(f) Project finance group:

(i) tracks actual spend against forecast spend;

(ii) manages DBNGP bank account;

(iii) prepares monthly and six monthly operational and financial reports;

(iv) liaises with internal audit processes; and

(v) manages day to day transaction services; and

(g) Project commercial group:

(i) negotiates terms and conditions for new contracts;

(ii) manages alliance contracts;

(iii) manages construction contracts;

(iv) assists with tendering processes (which will be managed by the Contracts Administration group within AAM); and

(v) interfaces with DBP in relation to OSA terms and conditions.

Contracting strategy

11.48 Once DBP had identified the lowest sustainable cost expansion option for Stage 5A, it ensured that the expanded capacity would be provided at – or below – the forecast cost, and on time. An appropriate contracting strategy was essential to achieving those outcomes.

11.49 As a prudent service provider, acting efficiently, DBP does not maintain its own engineering and technical staff capable of undertaking all of the design, development, acquisition and construction of facilities required to expand the capacity of the DBNGP. For the technical services required for pipeline expansion, DBP draws on the technical expertise of AAM, via the Operating Services Agreement (noted in paragraph 11.44 above), and on its alliances with other suppliers of equipment and engineering services. This has become standard industry practice within the pipeline industry.

11.50 A range of methods is available for securing the services of suppliers of equipment, and of engineering and technical services. At one end of the spectrum, that equipment or those services may be secured through fixed price contracts with suppliers. Somewhere along this spectrum is the method of engaging a supplier under a schedule of rates contract so that the contractor is better able to exclude contingencies from its pricing. At the other end of the spectrum, equipment, and engineering and technical services, are secured through relational, or alliance, contracts

11.51 In alliance contracting, the party requiring equipment, or engineering and technical services, forms an alliance with the contractor, enabling both parties to work co-operatively to deliver required facilities of the desired quality at the best possible price. Alliance contracting delivers these outcomes through its facilitation of knowledge flow between the parties, and the provision of incentives for the sharing of knowledge.

11.52 Alliance contracts provide beneficial cost and service related outcomes relative to lump sum contracts (even when those contracts are the results of tender processes) for the following reasons:

(a) the supplier is able to mobilize quickly;

(b) the buyer of services can exert a high level of control over any contract work carried out by the supplier (that is, by the alliance partner);

(c) the buyer can more readily change the delivery approach to accommodate project changes;

(d) alliance partners usually have a good understanding of projects and risks;

(e) there is the greatest likelihood of meeting tight deadlines;

(f) under lump sum or schedule of rates contracts, there is a steep learning curve for the supplier which will be factored into the pricing, resulting in an increased price for service provision;

(g) lump sum and schedule of rates contracts take time to formalise, and this may not be appropriate in circumstances where (as is the case with Stage 5A) a New Facility must be designed, and constructed or acquired, in a short period; and

(h) specification of the full scope of work for inclusion in a lump sum or schedule of rates contract takes time, and the buyer bears the risk of later scope change.

11.53 DELETED

11.54 DELETED

11.55 The benefits of adopting an alliance contracting strategy have been demonstrated in DBP's Stage 4 expansion of the DBNGP:

(a) the accumulated knowledge of the project managers, designers and constructors has been passed on from one phase of the work to the next phase, allowing better optimization in facilities design as lessons learned are continuously incorporated into ongoing work, and enhancing productivity in project execution;

(b) the speed with which the alliance team has been able to respond to emerging issues and changes has been exceptional, allowing work to begin quickly and progress rapidly without the owners being burdened with the need to prepare water-tight scopes of work, and to negotiate remuneration;

(c) an "open" environment has permitted different project participants [DELETED] to perform project roles on a "best fit" basis for each project task identified, and to complement each other to enhance the overall effectiveness of team performance;

(d) the project team has been able to focus on the prompt and effective implementation of design changes required during project execution, rather than on the preparation of extensive documentation for change justification (in adversarial – rather than alliance – contracting, such documentation is essential for negotiating changes to costs and schedule, but it has little residual value once cost and schedule issues are resolved);

(e) significant cost and schedule benefits have been achieved: although Stage 4 is being executed in an extremely buoyant market with rapidly escalating prices, the first two stages of the project (work at Compressor Stations 3 and 9) have been completed within baseline budget, and within baseline schedule, with a significant portion of the project contingency unused;

(f) all project participants, including DBP's representatives, work as part of an integrated team, rather as separate groups, each with its own supervision and management structure (as in traditional contracting), and this has eliminated duplicate functions across participant organizations and reduced administrative costs;

(g) under alliance contracting, there is no incentive for any project participant to "cut corners", and this has directly contributed to higher quality work in project execution, and to an outstanding safety record while delivering a fast track project under difficult conditions.

11.56 Although DBP proposes to continue its alliance arrangements for Stage 5A, a significant part of the materials requirement and construction work will still have to be sourced through conventional tendering and contracting processes. Presently, it is envisaged that contracts for looping construction and for compressor station construction will be the subject of competitive tenders.

11.57 Due to the limited number of manufacturers of the type and size of pipe required for the Stage 5A, the pipe manufacture and supply contract will be placed following a competitive benchmarking process to be undertaken by DBP and AAM. This will involve benchmarking the supplier of the pipework for the Stage 4 project with prices to be obtained from manufacturers in China and Korea. The timing requirements of shippers and potential loss of current commercial arrangements with contractors for the Stage 4 project do not enable DBP to undertake a complete competitive tender process for the pipe supply contract.

11.58 DELETED

11.59 DELETED

11.60 Evaluation of tenders will involve an assessment of each tender against the following criteria:

(a) commercial terms and provisions;

(b) technical conformance; and

(c) value, including, but not limited to, the following:

(i) financial elements (direct);

(ii) life cycle costs analysis;

(iii) product liability coverage;

(iv) total supply chain management;

(v) quality processes and systems (TQM and accreditation);

(vi) customer focus and responsiveness;

(vii) reliability of performance; and

(viii) financial capability of company.

11.61 Regardless of whether a contractor is engaged pursuant to an alliance agreement, or through a competitive tender process, it is a requirement of the Operating Services Agreement that the standard of work to be performed must:

(a) in all material respects comply with all applicable laws (including occupational health and safety legislation), codes, policy, regulations or orders or governmental bodies having jurisdiction;

(b) be in accordance with the terms and conditions of all material contracts and applicable licences;

(c) generally be in accordance with good industry practice;

(d) be undertaken in a manner which achieves the key performance indicators;

(e) be undertaken in a timely, commercial, prudent and reasonable manner;

(f) comply with the asset management plan for the DBNGP; and

(g) be undertaken with the required level of expertise (namely holding all material authorisations and accreditations).

Stage 5A contracting

11.62 The following principal contracts were required for the execution of Stage 5A:

(a) line pipe procurement (including coating and transport);

(b) looping construction;

(c) compression equipment procurement; and

(d) compressor construction.

11.63 Each of these is discussed in the following paragraphs of this submission.

Line pipe procurement

11.64 DELETED

11.65 Different pipe wall thicknesses were required on different sections of the DBNGP, and were determined from a design pressure of 10,200 kPa, and design factors of 0.72 0.6 for “light wall” and for “heavy wall” pipe respectively.

11.66 The pipe was externally coated using the same coatings that have been used in recent Australian and international pipeline projects. The pipe was also to be internally coated to improve its friction factor.

11.67 Ten API accredited international pipe mills were approached via e-mail letter of introduction and asked to provide current line pipe prices with a +/- 5% accuracy. Only one pipe mill in the world was capable of producing 26 inch ERW pipe.

11.68 ERW pipe is produced from hot rolled coil, and the production process has cost and availability benefits over production of SAW pipe from plate steel.

11.69 Moreover, it was possible for ERW line pipe to be supplied in lengths of 18 metres (rather than 12 metres) which reduces the quantity of welding and non destructive testing required, and reduces the requirement for joint coating, further reducing pipeline cost.

11.70 The pipe manufacturer is also to be responsible for pipe coating, although DBP had the ability to strictly control the coating process.

11.71 Coating took place in Kuantan, Malaysia. The establishment of a dedicated on-shore coating plant was now deemed feasible. Its establishment required a lead time of at least six months, with the possibility of delay in the development of the application process.

11.72 Three external coating options were considered. They were single layer FBE, dual layer FBE and Trilaminate. The final choice of coating was determined by resistance to damage during handling, and resistance to installation damage.

11.73 The internal coating in all three cases was 50 micron epoxy.

11.74 Due to its high diameter to thickness ratio, the pipe was assessed to be susceptible to damage during ship loading, transit, and unloading. This restricted the types of ships that might be engaged to transport the pipe to and from the coating plant to self geared full open hatch box hold vessels.

Looping construction

11.75 A single contractor was sought for all looping construction to be carried out for Stage 5A. The contractor was selected through a competitive tender process.

11.76 The looping contractor was responsible for:

(a) receipt, inspection, handling, transport and installation of line pipe (and all other materials supplied by DBP);

(b) procurement and supply of minor materials;

(c) provision of construction management;

(d) provision of site facilities, resources logistics and accommodation;

(e) construction and testing of the pipeline loops and interconnections to existing DBNGP facilities at each end of each loop, installation of all crossings, including potential horizontal directional drilling at major river crossings;

(f) commissioning of the looping works; and

(g) provision of assistance to DBP in the initial operation of the looping works including the initial filling with natural gas.

11.77 More specifically, the looping contractor was to undertake a detailed scope of works, [DELETED]**.** This can be summarized as follows:

(a) receive, inspect and take custody of the DN650 internally and externally coated line pipe free along side DBP's ships at the ports of Jervoise Bay and Geraldton, transport (in accordance with the coating specifications) the pipe to stockpile locations, and from there deliver the it to the pipeline right-of-way;

(b) receive and take custody of all items nominated on DBP's free issue list at DBP's depot in Perth and inspect the condition of these items;

(c) provide all materials necessary for completion of the project, other than those materials supplied by DBP as free issue items;

(d) provide all works management services, including systems and procedures for carrying out the work (including planning, scheduling, cost control, quality control, occupational health and safety, and supervision of personnel), for supervising the work. and for monitoring the work under contract for the duration of the project;

(e) supply, operate and maintain an electronic management system to track DBP supplied materials;

(f) develop and implement a quality management plan for the work under contract, and provide qualified and experienced inspection and test personnel to witness and record all construction test activities;

(g) assist in the development and implementation of, and in ensuring compliance with; the Construction Risk and Safety Case for the work under contract;

(h) coordinate activities with third parties including DBNGP operator;

(i) obtain all required approvals from relevant authorities where those approvals must be issued in the name of the contractor;

(j) conform to all requirements of regulatory authority approvals granted to DBP and the project, and conform to all of the Pipeline Licence PL 40 requirements for operation of the DBNGP by DBP;

(k) provide environmental controls in accordance with the CEMP, and associated management procedures nominated by DBP and the environmental regulators including but not limited to:

   (i) complaint response protocol;

   (ii) conservation area management protocol;

   (iii) dewatering and water disposal management protocol;

   (iv) dust management protocol;

   (v) fauna interaction protocol;

   (vi) fire management protocol;

   (vii) flora management protocol;

   (viii) fuel and chemical storage and handling protocol;

   (ix) heritage management protocol;

   (x) noise management protocol;

   (xi) rehabilitation management protocol;

   (xii) river crossing protocol;

   (xiii) vegetation management protocol;

   (xiv) waste management protocol;

   (xv) weed, pest and dieback management protocol; and

   (xvi) wetland management protocol;

(l) provide an adequate number of registered fauna handling personnel to comply with the fauna interaction protocol;

(m) provide suitably approved and trained cultural heritage monitors where required to complete work in accordance with heritage management procedures nominated by DBP and regulators;

(n) provide all plant, equipment, and light and heavy vehicles for pipeline construction, and provide fuels, lubricants, consumables, spare parts, maintenance and servicing to ensure that that plant and equipment is maintained in a good working condition and compliant with relevant safety and environmental requirements;

(o) provide temporary accommodation camps to enable the workforce to be accommodated at several work sites at any one time, with the campsites being fully self sufficient and provided with electricity supplies, drinking water supplies, sewerage, waste disposal facilities, communications, first aid facilities and other support facilities to the approval of all relevant authorities and DBP's representative;

(p) allow for a cumulative total of eight rooms at the mainline construction camps to be used by DBP at all times, and for catering for DBP's occupants plus an additional six personnel at all times;

(q) provide, for use by DBP, suitable air-conditioned office accommodation of a standard the same as that provided for the contractor's senior management with the following:

  (i) offices fully furnished to accommodate 10 personnel;

  (ii) telephone system and internet access for 10 personnel;

  (iii) photocopying and printing facilities; and

  (iv) tea and coffee making facilities, including refrigeration;

(r) provide diesel fuel and vehicle refuelling facilities for up to eight DBP and associated vehicles, and facilities for minor repairs including tyre puncture repair;

(s) survey the pipeline;

(t) provide site engineering works;

(u) construct the nominated pipeline loop sections and facilities, with all pipeline work carried out in accordance with AS 2885, the Technical Specification for Pipeline Construction, all referenced codes and standards, the drawings, the Construction Line List, the CEMP, all other applicable specifications including specifications pertaining to quality and safety, and DBP's Permit to Work procedures;

(v) provide equipment and services to manage acid sulphate soils expected on sections of the pipeline, and minimise open trench time to a maximum of 48 hours in nominated high and medium risk acid sulphate soil locations where acid sulphate soil treatment has not been applied;

(w) carry out hydrostatic and seal tests, including high pressure closure tests and high pressure seat/seal tests, on free issue Hot Tap valves;

(x) fabricate offsite, and hydrotest, mainline valves, associated bypass assemblies and (where practicable) start-of-loop and end-of-loop piping;

(y) install Stage 5A start-of-loop facilities to tie into the downstream ends of the Stage 4 loops, and tie the Stage 5A loop ends into the DBNGP at the flanged hot tap locations;

(z) install mainline valves into pre-hydrotested and dried pipeline sections, and install ancillaries including fencing, electrical conduits, and conduits for instrument cabling;

(aa) manufacture and install cold formed bends, and install DBP-issued hot formed induction bends in locations approved by DBP;

(bb) blast prepare, coat and compliance and holiday test all welded joints, with coating materials provided by contractor; and holiday test all of the factory coating prior to lowering the pipeline into the trench, and repair all coating defects identified;

(cc) undertake the necessary surveys to confirm that rivers can be crossed using the proposed open cut methodology and provide a Construction Method Statement;

(dd) nominate horizontal directional drilling construction for any of the crossings if this is cost effective over conventional techniques and, if approved by DBP, install the crossing by horizontal directional drilling and test the integrity of the pipe coating in accordance with the Technical Specification for Pipeline Construction before tying in;

(ee) install pipeline loops crossing under major rivers;

(ff) pre-hydrotest river crossing strings at each river crossing, prior to installation as a separate test;

(gg) apply concrete coating to free issue line pipe in accordance with the specifications and drawings, and install at the major river crossings in accordance with the detailed watercourse drawings;

(hh) install crossings at all roads, watercourses, railway tracks, drains, gullies, and services (power lines, gas pipelines and telecommunications lines);

(ii) install buoyancy control devices on the pipeline close to major watercourse crossings at the locations identified on the detailed watercourse crossing drawings;

(jj) install heavy wall pipe (11.7mm wall) and extra heavy wall pipe (14.6mm wall) at all locations where shown on the alignment sheets and the referenced detailed drawings;

(kk) provide, install, test and energize temporary cathodic protection facilities;

(ll) provide, install, test and energize permanent cathodic protection facilities;

(mm) provide (less free issue items), install and test instrumentation as indicated and defined in the specifications and drawings;

(nn) provide (less free issue items), and install AC mitigation systems including zinc ribbon earthwires and zinc anodes as indicated in the alignment sheets, and cable into Type J test points at the positions nominated;

(oo) clean, flush, hydrotest and dry each of the pipeline loops, including pre-tested sections, main line valves, and end-of-loop piping, and provide NATA certification for the test results;

(pp) run a gauging plate pig through the completed loop sections to demonstrate that each section is dent and buckle free, and to verify the internal diameter of the pipeline;

(qq) gather as-built data progressively during construction using approved systems with palm-pilots, differential GPS and other associated data loggers and data management tools;

(rr) complete all as-built data records and insert data into design drawings, including redline mark ups of DBP supplied drawings and documents, and into final reports within 14 days of mechanical acceptance for use by DBP;

(ss) re-spread all excess spoil and rock material from the right-of-way, or dispose of the material at approved sites, to the satisfaction of DBP's representative, and to the satisfaction of relevant landowners and local authorities;

(tt) reinstate and re-contour disturbed ground both on and off the easement in accordance with the CEMP, install contour banks, re-seed, and apply other stabilization methods on slopes or erosion susceptible areas;

(uu) commission the works;

(vv) assist DBP with start-up operations; and

(ww) carry out a Direct Current Voltage Gradient (DCVG) Survey of the pipeline coating within 12 months after completion of the backfill operation, and excavate and repair all coating defects within 30 days of DCVG survey.

Procurement of compression equipment

11.78 DELETED

11.79 Reliance on the existing alliance agreement, rather than procurement by new tender process, was essential if DBP was to obtain and install the compression equipment required for Stage 5A by the time the capacity of the expansion was to be made available to shippers.

11.80 DELETED

11.81 The compressor unit for CS1, was sourced [DELETED] because:

(a) DELETED

(b) the unit proposed for Stage 5A has a proven design, and has been independently service tested;

(c) testing and commissioning procedures for units are established and well understood by AAM personnel;

(d) with a number of the same units already in service on the DBNGP, the spare parts inventory can be optimized;

(e) DELETED

(f) the specification for the Solar unit for Stage 5A can use the specification for identical units sourced for Stage 4, reducing engineering costs, and reducing the time for decision making by at least 12 weeks; and

(g) DELETED

11.82 DELETED

11.83 For the turbine up-rating and compressor restaging, supplied:

(a) equipment and software for Mars 100 control systems, and new Centaur control systems;

(b) new interconnection shafts, and associated parts;

(c) equipment for exhaust upgrade;

(d) vibration control upgrade

(e) restaging special tools; and

(f) spare parts;

(g) performance testing.

(h) new compressor bodies

11.84 Turbine up-rating and compressor unit restaging requires detailed knowledge of, and engineering expertise specific to, the compressor units to be restaged. DBP therefore intended to have the manufacturer, [DELETED], supply and install the equipment for the restaging of the PGT10 units located at CS6/2 and CS9/1.

11.85 Compressor station pipework, fittings and flanges were sourced from alliance partner [DELETED] and were subject to satisfactory benchmarking of the proposed costs against Stage 4 costs for similar items.

11.86 All other compressor station equipment - scrubbers, aftercoolers, gas engine alternators – was sourced by restricted competitive tender processes.

Compression construction

11.87 A single contractor was sought for all compression construction to be carried out for Stage 5A. The contractor is to be selected through a competitive tender process.

11.88 The compression construction contractor was responsible for the following work [DELETED]:

(a) supply and install 10 MW turbine/compressor unit complete with on skid enclosure;

(b) supply and install remote lube oil cooler for new turbine/compressor unit;

(c) supply and install fuel gas filter rack for new turbine/compressor unit;

(d) supply and install below ground waste water transfer tank;

(e) supply and install new double skinned above ground lube oil storage/waste water collection tank complete with vacuum transfer pump for new turbine/compressor unit;

(f) supply and install air inlet filter/ducting for new turbine/compressor unit; and

(g) supply and install exhaust silencer/ducting for new turbine/compressor unit.

11.89 Details of the work to be carried out by the compression construction contractor were as follows.

11.90 Piping:

(a) compressor process piping:

(i) supply and install suction and discharge piping for new compressor unit;

(ii) supply and install new check valve in the station header between tie-in for new compressor suction and the station after cooler; and

(iii) supply and install recycle piping for new compressor;

(b) waste water piping: supply and install waste water drain piping between new compressor enclosure and new transfer/collection tanks;

(c) lubricating oil piping: supply and install lubricating oil piping from turbine/compressor unit to lubricating oil coolers;

(d) fuel gas piping: supply and install fuel gas piping (including filter and PRV's) to new turbine.

11.91 Instrument gas piping:

(a) supply and install instrument gas pressure reduction skid for the new turbine/compressor unit; and

(b) supply and install instrument gas piping to instrument gas consumer points associated with the new turbine/compressor unit.

11.92 Civil and concrete:

(a) clear ground, prepare finished ground levels, and excavate and backfill for new turbine/compressor installation;

(b) install concrete footings for new turbine/compressor unit and enclosure, turbine inlet filter and ducting, turbine exhaust silencer, enclosure ventilation inlet filter and ducting, and enclosure ventilation exhaust;

(c) install concrete ground slab apron around new turbine/compressor enclosure;

(d) install concrete raft footing for new turbine/compressor lube oil cooler;

(e) install concrete raft footing for the fuel gas skid associated with the new turbine/compressor;

(f) install concrete raft footing for the instrument gas skid associated with the new turbine/compressor;

(g) install concrete footings for pipe supports, valve platform and pipe crossovers for process gas piping associated with the new turbine/compressor installation;

(h) excavate and backfill trenches for piping, cable ducts and pits, and electrical, instrument and control cabling; and

(i) install concrete footings for off-site fabricated 'local' unit switchgear and control room.

11.93 Structural:

(a) supply and install new off-site fabricated 'local' unit switchgear and control room;

(b) supply and install structural steel to support turbine inlet filter and enclosure ventilation inlet filter associated with the new turbine/compressor unit; and

(c) supply and install structural steel to support the lubricating oil cooler associated with the new turbine/compressor unit.

11.94 Electrical:

(a) supply and install new unit MCC c/w with the following drives:

(i) new compressor unit starter motor feeder and Solar supplied VFD;

(ii) new compressor enclosure DOL ventilation fans;

(iii) new compressor unit lube oil cooler fans;

(iv) new compressor unit lube oil pump;

(v) new compressor lube oil sump decant pump;

(vi) miscellaneous ventilation/air conditioner feeders; and

(vii) new compressor enclosure lighting and small power panel feeder;

(b) cabling, ducts and ladders:

(i) supply and install power, control and instrumentation cabling to new turbine/compressor unit and ancillary drives;

(ii) supply and install A/G cable ladder system within switchgear / control room; and

(iii) supply and install U/G cable duct system to the new compressor enclosure.

(c) 24V DC power supply:

(i) install Solar supplied 24V DC UPS system in switchgear/control room;

(ii) supply and install new compressor unit 24V DC distribution board; and

(iii) modify existing station 24V DC system to accommodate new equipment;

(d) 110V DC power supply: modify existing 110V DC power supply system to provide feeder to the new turbine/compressor unit emergency lubricating oil pump;

(e) lighting and small power:

(i) supply and install new turbine/compressor unit lighting and small power distribution panel;

(ii) supply and install lighting and small power to new turbine/compressor unit enclosure and surrounds;

(f) earthing and cathodic protection:

(i) modify existing cathodic protection TRU to provide new circuits;

(ii) supply and install cathodic protection cables and test points; and

(iii) supply and install new earthing and lightning protection to new turbine/compressor enclosure and surrounds;

11.95 Instrumentation and control systems:

(a) supply and install pressure, differential pressure, temperature and level transmitters; indicators and switches to the new turbine/compressor unit off-skid piping and ancillary equipment;

(b) supply and install new ultrasonic flow meter in pipeline at entrance to compressor station;

(c) supply and install additional hardware and modify existing unit control systems to suit installation of additional turbine/compressor unit; and

(d) supply and install additional ACF/load shed PLC hardware and cabinet, to be integrated with existing ACF/load shed PLC;

11.96 SCADA and telecommunications:

(a) modify and upgrade existing SCADA system to suit installation of additional compressor unit and associated station equipment; and

(b) provide additional public address and telephone circuits for new facilities;

11.97 Fire and gas systems:

(a) supply and install new fire and gas system for new turbine/compressor unit; and

(b) supply and install new fire and gas system for unit switchgear and control room.

Stage 4 experience: on budget and on time

11.98 At the time of planning for Stage 5A DBP was expanding the capacity of the DBNGP to provide an additional 124.9 TJ/d of full haul T1 capacity. The expansion project – Stage 4 – was then well advanced, and scheduled for completion on 1 January 2007.

11.99 Stage 4 comprised:

(a) the installation of seven new 10 MW compressor units, one at each of Compressor Stations 1, 2, 3, 4, 6, 7 and 9, and one 7 MW compressor unit at Compressor Station 10; and

(b) construction of 194 km of pipeline looping in segments downstream of Compressor Stations 1 to 9, and 23 km of looping downstream of Kwinana Junction.

11.100 The 10 MW compressor units being installed are Mars units supplied [DELETED].

11.101 In addition to being on schedule, Stage 4's overall costs were also forecast, at the time, to be on budget.

11.102 The proposed costings for Stage 5A had, where available, been estimated having regard to unit costs for the Stage 4 costs for the following reasons:

(a) The largest contract for Stage 4 has been the subject of a competitive tender process (being the looping construction contract).

(b) Contracts entered into for the supply of compressors have been benchmarked against other potential suppliers, with the results confirming that the unit cost estimate for each compressor is the lowest from potential suppliers.

(c) The costs for Stage 4 are to be passed on to shippers under the Standard Shipper Contract. However, in doing so, DBP is required, under the Contracts, to seek to minimise the capital costs of the expansions, without derogating from its obligations to act as a reasonable and prudent person and to follow standard industry practice.

11.103 As was the case with the Stage 4 process (in which respect see paragraph 8.28 of this submission, the project was reviewed by the independent engineer who undertook the same scope of work as was undertaken for stage 4. [DELETED].

12. STAGE 5A ACTUAL EXPENDITURE

12.1 **Error! Reference source not found.** contains a detailed breakdown of the actual expenditure incurred in respect of 5A. This has been reconciled with the amounts attributed to each asset class in the Access Arrangement in the table in section 9 of this submission.

12.2 DELETED

13. STAGE 5B PRUDENCY OF DESIGN

13.1 A summary of the expenditure involved in Stage 5B is in the table below:

	Actual		Forecast	
	2008	2009	2010	2011
Stage 5B Compression	-	-	155,000,000.00	-
Stage 5B Pipeline	-	-	450,000,000.00	-
Stage 5B Other	-	-	15,900,000.00	50,000,000.00
Linepack	-	4,450,252.25	-	-
Total Expenditure	**-**	**4,450,252.25**	**620,900,000.00**	**50,000,000.00**

13.2 Stage 5B is considered to be an extension of Stage 5A with a similar scope of supply. As such, most of the documentation prepared for Stage 5A is considered to be equally applicable for Stage 5B.

13.3 Importantly however is the fact that the Stage 5B project was approved in 2 phases – the first being for a smaller tranche of capacity (originally known as the Stage 5A2 project – being the additional capacity to be provided to shippers who, at the time an investment decision was made for stage 5A, were not in a position to commit to the additional capacity under the 5A expansion), and the second being for the remainder of the 5B capacity.

13.4 In mid-2007, DBP received confirmed capacity requests from a number of shippers that underwrote the Stage 5A2 expansion project delivering the following ("Stage 5A2 capacity"):

- 28 TJ/day Full Haul;
- relocation of 10 TJ/day from Part Haul to Full Haul; and
- 20 TJ/day Part Haul

13.5 The shippers requesting the Stage 5A2 capacity under Stage 5A2 had long lead times for their capacity start dates (in 2010 and 2011). So, there was no immediate pressure once the investment decision was made to place orders for some of the long lead procurement items such as line pipe and valves.

13.6 However, given the resources driven economic boom that was being experienced in Western Australia during 2006 and 2007, there was an increase in demand, albeit most of it involved shippers either firming up their level of firmness of capacity or relocating capacity to outlet stations downstream from their then outlet stations.

13.7 Accordingly, before orders for the long lead items needed to be placed, DBP received further confirmed capacity requests ("additional capacity") which were for start dates through 2010. Accordingly, the decision was made to consolidate the Stage 5A2 project into a larger program to be referred to as the Stage 5B Expansion Project.

13.8 At the time the investment decision had been made for 5B, the engineering and much of the procurement for what was Stage 5A had recently been completed. Stage 5B incorporated and built on the scope of 5A. Much of the design effort and the materials and equipment ordered for 5A were used for 5B.

13.9 Notwithstanding that, similar processes were followed for the design options for stage 5B as were used for assessing options for stage 5A. [DELETED]

Scope of Work - Facilities (Compressor Stations)

13.10 The high level scope of work for Facilities included:

(a) Five Gas Scrubbers

(b) The replacement of the C505 Gas Compressor at CS1 with a C652 Compressor

(c) Three additional Switchrooms

(d) Four 850kW Gas Engine Alternators (GEA's)

(e) Three 600kW Diesel Engine Alternators (DEA's)

(f) The installation of a Taurus compressor unit and associated facilities at CS10

(g) The upgrade and modification of station pipework to eliminate high flow noise and vibration

(h) Replacement of Annubar unit flow measurement facilities with Venturi flow meters

(i) Installation of station suction flow meters at some sites

(j) Fire and gas system upgrades at each station

(k) Improved reliability at CS9

(l) Decommissioning of two 230kW GEA's from CS4 and CS7

(m) Upgrade of a Nuovo Pignone spare compressor turbine engine for use as a spare for CS6 and CS9.

(n) Upgrade of 4 meter stations south of Kwinana Junction (addition of heaters)

(o) BEP Interconnect at MLV7

13.11 DELETED

Looping (Pipeline)

13.12 DELETED

13.13 In summary, a total of approximately 440.3km of additional pipeline loops is required to be installed alongside the existing DBNGP in Stage 5B. The additional looping will be extensions of the current loops and spread across all eleven sections of the pipeline (Loops 0 through 10). A total of 10 MLV's will be installed on 7 of the loop sections. The loops will also incorporate end of line facilities for connecting into the existing DBNPG at the end of the Stage 5B loops. This is the most efficient means of expanding.

13.14 However, given that it will result in the mainline north of CS9 being looped for more than 85% of its entire length, the efficiencies generated by looping (in terms of additional capacity created per kilometre) begin to fade. Also, the need for compression becomes relevant to ensure deliveries in the southern part of the system (downstream of CS10).

13.15 Stage 5B builds on previous DBNGP expansion projects, utilising the facilities and equipment already installed. These are assumed to be in good working order and well maintained, however they will be reviewed for adequacy to cope with the additional capacity demands. Existing facilities and equipment will be assessed and if not fit for purpose for the enhancement will be included in Stage 5B development.

13.16 Where the scope later diverges from the original assessment and the facilities or equipment is found to be deficient, the cost to bring the existing facilities and equipment to the required rated performance will be in addition to the baseline project budget and access to project contingencies will be sought. Equipment that is obsolete or at the end of its useful life will need to be replaced using stay in business capital and will not be funded by this expansion project.

Cost Estimate

13.17 The budget for 5B was prepared for the DBNGP Stage 5B Expansion Project based on costs already incurred for Stage 5A. Cost estimates are based on 2008 material and labour costs. Escalation (CPI plus market forces increases) from these prices to price at time of procurement and project implementation has been included within the final documented costs. [DELETED]

13.18 The Looping cost estimates are based on the proposed line pipe contract [DELETED] but assume competitive tendering for the construction contract. An initial tendering process for looping construction was used to validate the looping construction cost estimate.

13.19 The Facilities cost estimate is based on a competitive tendering approach for the construction contract.

13.20 Costs for materials already committed to or purchased under Stage 5A-2 were considered when determining appropriate rates for escalation.

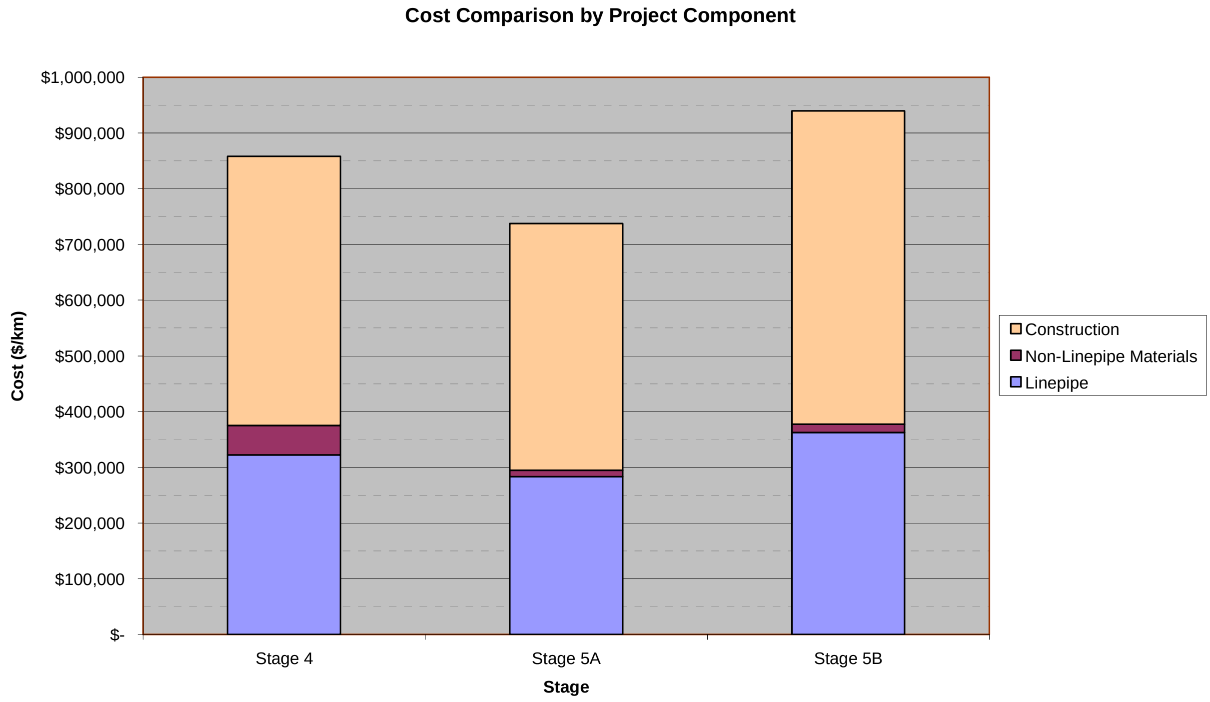
13.21 A Monte Carlo probability analysis was performed to evaluate project risk and determine contingency. Representatives from the project manager and the integrated design team attended the workshop, as did key representatives from DBP.

13.22 DELETED

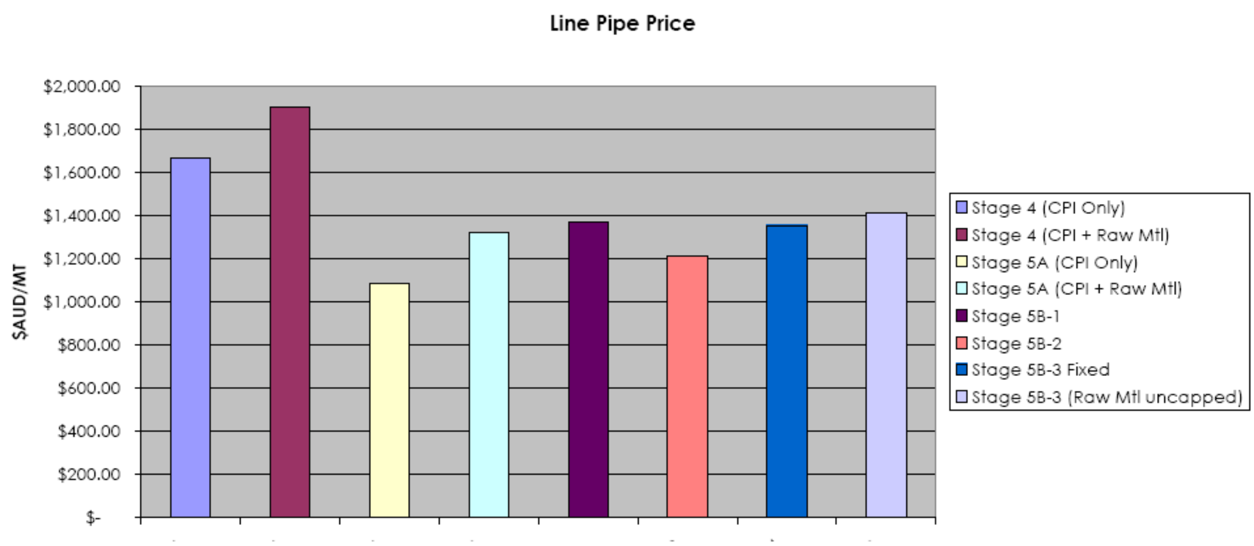
Stage 5B Project Cost Summary (Revised 8 May 2008)		
Activity		AUD
Facilities		
Materials and Equipment	$	54,675,714
Construction	$	59,450,000
Engineering, Procurement & Construction Management	$	13,177,691
HSE Costs	$	742,076
Service Contracts	$	2,160,000
WestNet Energy Costs	$	5,200,000
Total	$	135,405,481
Looping		
Materials and Equipment	$	6,498,116
Line pipe	$	154,559,409
Construction	$	245,123,518
Engineering, Procurement and Construction Management	$	6,326,817
WestNet Energy Costs	$	8,868,000
Site Support Costs	$	5,590,450
Service Contracts	$	3,944,600
HSE Costs	$	5,800,266
Corporate Affairs Support for Loop 9	$	236,000
Media Archive	$	50,000
Total	$	436,997,175
Overheads		
Project Overheads	$	15,802,000
Linepack	$	987,626
Legal	$	300,000
Insurance	$	5,000,000
Independent Engineer	$	200,000
Shutdown/Commissioning Cost/Fuel Costs	$	2,300,000
BEP (CAPEX)	$	2,000,000
Total	$	26,589,626
Baseline Before Escalation	$	598,992,283
Escalation on Labour	$	19,090,278
Escalation on Materials (CPI at 3% on 60% of Non-Labour)	$	6,962,045
Baseline Including Escalation	$	625,044,605
Project Contingency (P50)	$	27,192,789
Baseline Including Escalation & P50 Contingency	$	652,237,394
WNE Margin	$	18,751,338
Overall Project Cost	**$**	**670,988,732**

DBNGP Looping Cost Comparison per Stage

13.23 Included below is a stacked bar chart showing overall Looping costs split into line-pipe, non linepipe materials, and construction. The values have been based on the data contained in this document, and have been escalated at similar rates as values contained within this submission.



13.24 Included below is a bar chart showing the overall AUD$/MT for bare pipe costs (FOB Japan) for Stages 4, 5A and 5B. The pipe costs have been escalated over time to consider the effects of both CPI and the relevant escalation clauses within the supply contracts:



13.25 DELETED

14. 5B DESIGN - INTENT TECHNICAL INTEGRITY & SCOPE

14.1 As a further indication of the prudency of the design and the project, the 5B design incorporated measures and features to ensure that the desired level of technical integrity was achieved by the following.

(a) Sound engineering design based on clearly defined technical and operational requirements

(b) Re-use of proven Stage 4 and 5A designs in Stage 5B.

(c) Adherence to fitness for purpose requirements ensuring essential compliance with Statutory requirements

(d) Selection of appropriate equipment for containment, corrosion management and maintainability for sustaining the intended asset operational life of 40 years (this life span will not apply to existing facilities that are reused as part of the Project) with consideration for:

(i) Vendor warranties will only apply for 1 year. However subsequent preventive and active maintenance will ensure equipment remains operable.

(ii) During detailed design, a comprehensive check of codes and standards will be undertaken to ensure that the design is fully compliant with the relevant codes and standards

(iii) The extension of plant life to 40 years will require periodical internal inspection of some equipment. This is to ascertain erosion, corrosion and/or fouling and re-certification to relevant codes at periodic intervals. For equipment such as pressure vessels and piping, such recertification may be preceded by an assessment of stress fatigue and comprehensive integrity assessments several times during the asset life.

(iv) As there is no water or air in the gas so mainstream facilities are unlikely to be subjected to severe corrosion; however periodic inspection to mitigate the effect of metal losses arising from upset or errant process conditions shall be planned.

(v) Oil in the gas stream may cause fouling of the pipeline and facility systems, with the greatest effect on the Aftercoolers due to their large surface area. Effective mitigation of such fouling by periodic inspection and remedial actions will prolong heat transfer efficiencies.

(e) Design validation by an independent 3rd party

Standardisation

14.2 Design shall maximise standardisation of identical or similar equipment in all parts of the development, providing that it leads to a cost effective solution. Due consideration shall be given to existing facilities albeit with proper regard for costs, current and future technologies and improvement in processes that are equally crucial for future facilities. In particular, it is proposed that the same vendors be utilised to supply the Gas Turbine Driven Centrifugal Compressor Unit, Scrubbers and the GEA's.

Facilities Scope

14.3 At completion of Stage 5B Expansion the DBNGP will be able to support firm full-haul capacity of approximately 846TJ/day at design conditions. The pipeline will be able to support higher flow rates during cooler winter months or higher gas heating value.

14.4 DELETED

14.5 Stage 5B modifications at the Compressor Stations has been confined to de-bottlenecking of the existing facilities to allow an increase in flow rate. It was intended to install new Scrubbers in parallel with existing facilities where appropriate.

14.6 Additional power requirements resulting from increased electrical loads on site and to improve reliability of compression will be provided by new Gas Driven Engine Alternators (GEA's) power generation facilities and Diesel Driven Engine Alternators (DEA's) on some sites.

14.7 Restaging (replacement of the Compressor impellers) arrangements were part of Stage 5A scope. However, further restaging is not required to meet Stage 5B loads. The C505 gas boost compressor at CS1 needed to be replaced with a C652 compressor. Note that this is just the driven equipment (compressor unit) and the gas turbine engine will not be replaced.

14.8 Formal discussions with the [DELETED] design team in San Diego confirmed that the optimal development process for [DELETED] compressors on the DBNGP is to restage and retain series operation for up to 2 units, and conversion to parallel operation with restaging when 3 units are required.

14.9 Station vent systems were reviewed for adequacy with the additional flow rates and the budget was made accordingly.

14.10 A number of items had been identified as being required to increase the reliability and availability of compressor station number 9. The following lists the most significant of these.

14.11 Install a second isolation valve (manual operation only) downstream of current unit isolation valves with a vent between the two valves. This will reduce the station outage times if work is required on any unit.

14.12 Install manual isolation valves for each of the aftercooler banks. This will allow online maintenance work on the aftercoolers, increasing availability of the station.

14.13 Replace the current control system on the Nuovo Pignone units. This system is obsolete and there is insufficient memory for the stage 5B enhancement.

14.14 Upgrade of a Nuovo Pignone spare turbine engine for use as a spare for CS9 (and CS6).

14.15 The overall scope of work for Stage 5B is outlined in the table below:

MATERIALS & EQUIPMENT	CS1	CS2	CS3	CS4	CS5	CS6	CS7	CS8	CS9	CS10	Other Sites
Mechanical/Piping											
Inlet Scrubber		1	1	1		1	1				
Aftercooler											
Vent Attenuator	1	1	1	1	1	1	1	1	1		
Station Piping Support Mods (elim. high flow noise & vib)	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	
FG PRS connection for GEA							Y				
FG Regulators						Y	Y				
GEA waste oil/fresh oil tank		1	1	1	1	1	1		1		
Unit suction strainers	2	2	2	2	2	2	2	2	2		
GEA FG heat recovery pipework							Y				
Compressor Station Pipe & Valves		Y	Y	Y		Y	Y				
Insulating Joints (26" x 600#)		2	1	2		1	1				
Y-Type Strainer & T trap		1	1	1		1	1				
Heaters at 4 meter stations											4
BEP Interconnect											1
Electrical											
850kW GEA		1		1		1	1				
Load Banks		1		1		1	1				
GEA Synchronisation Panel						1					
Synchronisation		Y	Y	Y	Y	Y	Y		Y		
Existing Switchgear Mods		Y	Y	Y	Y	Y	Y		Y		
Sundry Equipment		Y	Y	Y	Y	Y	Y		Y		
Decommission 230kW GEA				1			1				
Permanent Standby DEA (600kW)			1		1				1		
Primary Switchroom					1	1			1		
Primary Switchboard (MDB-GEA)			1		1	1			1		
Station Services MCC (MDB-SS)		1	1	1	1	1	1		1		
Temporary DEA (600kW) (fuel and hire)		1		1		1	1				
Load Bank PLC											
Upgrade 24V & 110V Rectifier systems						Y			Y		
Upgrade the ControlView MMIs	Y		Y		Y			Y			
Upgrade old Station PLC CPU (GE series 6)		Y	Y	Y		Y	Y				
Upgrade GEA Melsec PLCs		Y	Y	Y			Y				
Terasaki Air Circuit Breakers		Y	Y	Y	Y	Y	Y	Y	Y		
UPS Power: 24V battery replacement & augmentation	Y	Y	Y	Y	Y	Y	Y	Y	Y		
Upgrade old Unit plc (GE series 6) located at CS3 (LM500)											
Upgrade C25 Conitel RTUs at	Y		Y		Y			Y			

MATERIALS & EQUIPMENT	CS1	CS2	CS3	CS4	CS5	CS6	CS7	CS8	CS9	CS10	Other Sites
compressor (CS 1,3,5 & 8)											
Instrumentation and Control											
Primary Switchroom Fire Equipment & Detectors											
Office Annex											
Actuated Plug Valves											
Install station flow meters	1		1		1			1		2	
Replace Annubar flow meas. with Venturi meters						1			1		
Power Management / Load Shedding	Y	Y	Y	Y	Y	Y	Y	Y	Y		
New Control System for NP Compressors						Y			Y		
Actuated Ball Valves	Y	Y	Y	Y	Y	Y	Y		Y		
Regulators & Relief Valves	Y	Y	Y	Y	Y	Y	Y		Y		
Station Control system	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	
Field Instruments	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	
Communications	Y	Y	Y	Y	Y	Y	Y	Y	Y		
Flow Computer Upgrade	Y	Y	Y	Y	Y	Y	Y	Y	Y		
Scada Modifications	Y	Y	Y	Y	Y	Y	Y	Y	Y		
Compression											
Replace C505 with C652	1										
New Taurus Compressor										1	
Maintenance											
Fire & Gas Compliance	Y	Y	Y	Y	Y	Y	Y	Y	Y		
CS09 Reliability Issues									Y		
Upgrade of the ST4 Solar Mars/Taurus fuel gas heaters	Y	Y	Y	Y		Y	Y		Y		
Equipment and Commissioning Spares	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	
Additional Facilities											
Accommodation Upgrade		1		1							
New Office Block											
Modification to existing facilities											1
Modification to existing facilities											1
Additional Car-parking											1
New Warehouse					1						1

Looping Scope

14.16 It was intended to install additional lengths of pipeline looping for Stage 5B at all existing loops (Loop 1 through Loop 10) as well as a new loop at Loop 0. Battery limits for the design and construction will begin with a new loop at Loop 0 from MLV7 followed by a tie-in to the inlet of CS1. All other loops will tie-in to hot taps on the DBNGP.

14.17 Permanent launchers and receivers were not part of the scope of work, however provisions were made for the installation of these.

14.18 Looping for Stage 5B [DELETED] includes the following:

(a) Approximately 440.3km of pipeline loops apportioned as follows :

	Additional Loop Lengths	Additional MLV's
Loop 0	115.1 km	3
Loop 1	32.9 km	1
Loop 2	31.9 km	1
Loop 3	34.6 km	1
Loop 4	33.6 km	0
Loop 5	34.0 km	0
Loop 6	35.8 km	1
Loop 7	44.0 km	1
Loop 8	21.8 km	0
Loop 9	23.4 km	2
Loop 10	33.3 km	0
TOTAL	**440.3 km**	**10**

(b) A start-of-loop tie-in using hot tapping at Loop 0 MLV 07.

(c) An end of loop tie-in using hot tapping at Loop 1 through 10.

(d) Loop 0 ends in a connection on the inlet to CS1. No hot tap is required.

(e) Installation of Main Line Valves Looping (MLVLs) on Loops 0, 1, 2, 3, 6, 7 and 9. MLVL locations are based on R1/R2 location classes not greater than 60km spacing from the previously installed MLV, and at a maximum spacing of 12km in densely populated areas; T1 location classes. These new MLVLs will be co-located with existing DBNGP MLV's.

(f) The head of Loops 7 to 9 inclusive include the installation of an isolation valve prior to commissioning. This enabled Stage 5B loops to be commissioned with the minimal of disruption to loop flow.

(g) Each end of loop incorporates an additional valve on the crossover to enable any subsequent Staged expansion loops to be installed without and disruption to the loop gas flow.

(h) For the end of line on Loop 10 a new End of Loop Pressure Reduction Skid (PRS) was installed but the monitoring and associated telemetry from the Stage 5A installation will be relocated to the Stage 5B End of Loop.

14.19 All end of line loop facilities incorporate provisions (buried blind flange and kicker offtake), for the installation of temporary pig traps, to allow the pipeline loops to be internally inspected by In-Line Intelligent Pigs.

14.20 Sequence of construction of the loops was determined by supply requirements and construction logistics and consideration of weather and groundwater level conditions. It was envisaged that the contractors would construct at a slower rate on Loop 9 and 10 due to urban congestion, whilst commencing construction of the northern loops at the same time.

14.21 The contractor is likely to support an earlier completion date to reduce costs.

14.22 It was not necessary to fabricate additional end of loop spools for Loops 1 to 10 as there was sets of both DN500 and DN650 left over from Stage 5A. However, an end of loop facility was required for Loop 0 as this is a permanent scraper receiving facility. Loop 9 terminates inside the MLV119 site.

14.23 Completed Loop 0 includes provisions for pig launching and receiving to allow for intelligent pigging of the line. The launching and receiving provision includes a full bore isolation valve to allow full double block where the trap is connected and provision for the attachment of a kicker line and an equalisation line. No launcher or receivers are provided as the existing units or units supplied by the intelligent pigging subcontractor can be used.

14.24 DELETED

15. 5B EXPENDITURE BUDGET

15.1 The following assumptions underpinned the expenditure budget for Stage 5B.

Facilities - Material and Equipment

15.2 Three GEA's have already been procured under Stage 5A-2, therefore one more GEA will have to be procured under 5B. The quantities are based on a recommendation from a study carried out by the existing Stage 5A project team in conjunction with Operations as part of the reliability review and modified to balance capital cost against reliability under peak conditions, taking load shedding into account.

15.3 Synchronisation will be required at each GEA site. At the time the budget was prepared, price was expected to vary depending on what has already been done at each site and what upgrades are required on existing equipment.

15.4 A Primary Switchroom and Primary Switchboard (GEA-MDB) were required at CS5, CS6 and CS9. Station Services (MCC - MDB-SS) were allowed for at sites where GEA's or DEA's are being installed.

15.5 All peripheral materials, e.g. piping, valves, instrumentation, switchgear, etc. have been allowed for.

15.6 Replacement of the CS1 C505 compressor with a C652 compressor has been allowed. This is required to better match the increased flows as a result of the commissioning of Stage 5B with the flows being transported for [DELETED] into the Goldfield Gas Pipeline. The replaced compressor will be held in DBP's warehouse to enable it to respond quickly to any compressor outages and therefore ensure reliability of supply is maximised.

15.7 Annubars will be replaced with venturi flow meters.

15.8 Insulation joints quantities are based on the design layouts made under Stage 5A-2. Six units are available to the project as surplus from Stage 5A.

15.9 Bulk item quantities ordered for Stage 5A were used to establish a pro rata estimate, given the project followed so closely off the stage 5A expansion project.

Construction

15.10 As was the case with prior project, given the requirements under the OSA, competitive tendering was to be used to determine the Stage 5B Facilities Construction Contractor.

15.11 Construction costs are based on an estimate provided by the existing construction Alliance partner as well as historical information from Stage 5A. This was adjusted on the basis that the existing construction Alliance partner appeared to have built in a substantive margin to protect its tender position.

15.12 Consideration was given to the remoteness of each site and the associated premium relative to that remoteness was also taken into account.

15.13 Mobilisation and demobilisation costs for stations with one piece of equipment will not differ markedly from that where two or more pieces were to be installed.

15.14 Camp accommodation for the Facilities construction crews were to use an integrated camp for the bulk of the construction activity supplemented with demountables as required.

15.15 New cables can be routed via existing pits and conduits and existing cable routes (pits, ladder, conduits, etc.) have capacity for utilisation in Stage 5B.

15.16 All GEA controls will be on-skid. The estimate allowed for only backbone control cables to be run from the control room to a Local Control Panel on the GEA skid.

15.17 New Fuel Gas piping and regulators will be provided for GEA's and some allowance has been made for new or additional Fuel Gas skids.

15.18 No additional fencing or modifications to existing station fence, relocation of helipads and removal or decommissioning of existing GEA's at any site is planned.

15.19 No vent stack works, other than vent attenuators is planned.

15.20 No control room extensions are planned.

15.21 CS9 Acoustic barrier works were to be required for accommodation units.

15.22 No Contractors risk insurance has been included. Project insurances are to be provided by DBP (for the benefit of the contractor).

Commissioning

15.23 Costs for the Construction and Commissioning management teams have been captured in the Engineering cost estimates.

15.24 It has been assumed that the team will comprise a Commissioning Manager; a Commissioning Superintendent; two Technicians; a Construction Coordinator; a Works Inspector and an OHSE Representative.

15.25 Offsite support costs have been allowed for to cover commissioning equipment, travel to and from site and any third party assistance that may be required.

15.26 Commissioning will follow construction at each site and the team will remain at the site until the commissioning is complete. The combined duration for both activities will not exceed ten weeks per site. It is likely that two construction teams will operate in parallel constructing two sites simultaneously as per Stage 5A.

Schedule

15.27 Design activities for Stage 5A-2 had commenced July 2007 and as most of that work is directly applicable to Stage 5B, the majority of the Engineering and Procurement activities were to be completed by September 2008. Project completion was planned for April 2010.

Line Pipe, Material and Equipment

15.28 New hot tap tees, valves, and other associated materials and equipment will be required for all loops.

15.29 A number of hot tap valves will be reclaimed therefore it is not necessary to procure a new hot tap valve for every loop connection

15.30 Line pipe costs for the initial 240km have been based on the Letter of Intent signed by DBP and Metal One and include a price escalation in line with annual steel negotiations. The remaining 200.7km is based on a fixed price offer to be finalised by DBP.

15.31 Line pipe will be 20 to 32 week delivery from placement of order to final shipping. Major equipment such as MLV's are up to 13 months and hot tap tees are expected to be 20 weeks delivery ex-works. This is based on information received from Metal One and other suppliers during the procurement of pipe for Stage 5A-2.

15.32 Line pipe costs include for the following:

(a) Bare pipe

(b) Hot Formed Bends

(c) Coating

(d) Shipping

(e) Storage

(f) Inspection

(g) Unloading, inspection and transfer costs

Construction

15.33 An initial construction cost estimate was based on the Stage 4 and 5A contracts and anticipated increased scope costs. This was further validated by an abridged tender process, in which tendered prices received indicated generally higher costs for labour, fuel, overheads, unquantified risks etc.

15.34 The looping construction cost estimate has been developed from the tender schedules provided by the bidders and where insufficient information was available suitable allowances have been made. An allowance has also been made for an additional 10Km's of looping as the bids were based on 430Km.

15.35 The prices received from the first pass of the bidding process clearly showed that the prices are directly linked to the level of effort exerted by the bidders during the review period. Therefore quotations were received from three bidders with various levels of qualifications and/or accuracy of estimating. To enable a realistic estimate being adopted for the purposes of this FEL the median of the three bids was used. The median was only used once each bid had been adjusted for bid qualifications, exclusions or additional DBP requirements. The adjustments were reflective of the risk allocation adopted by each bidder and their perceived understanding of the scope of work.

15.36 The selected construction contractor was to supply all construction labour, plant, necessary sub-contractors camps, management and miscellaneous materials. A competitive negotiated tendering process was to continue until a selected contractor is approved by DBP.

15.37 Construction and commissioning was to run from March 2009 to April 2010.

15.38 The construction sequence was determined by gas supply requirements taking into account weather restrictions (such as cyclones etc) and the environmental conditions attaching to the construction approvals.

15.39 Some Acid Sulphate Soils / water were expected, as this work entails significant laboratory tests after field drilling, a "worst case" has been placed in the tender document for bidding. After the tests are finalised and before the final tender price is accepted the results of the test shall be priced against the worst case. No major rock formations have been identified, however, no field work has been performed at this stage, Loop 0 has some indications of rock and bidders have allowed for approved blasting of this section.

15.40 CP, AC mitigation, E & I and hydrostatic testing proportioned based on a ratio of Stage 5B length to that of Stage 5A and is included in contractors scope

15.41 Camps & accommodation proportioned based on a ratio of Stage 5B length to that of Stage 5A with a strategy to reduce daily travel allowed.

15.42 Commissioning costs were also incorporated in the construction cost estimate.

15.43 Pipe yard preparation has been included in the construction section as the option to renew the current storage yard at Dampier has been rejected by the landlord as the land is required for other purposes. Additional costs for longer transportation between yard and wharf has been allowed for.

15.44 Major items such as rivers and roads were reviewed against alignment sheets and costs adjusted per loop. The accuracy of the alignments could not be verified in the timeline and have been treated with caution. Major rivers and creek estimates have been worked from Stage 4 major river crossing costs based on open cut only. Contractors were to have the opportunity to submit HDD methods for large river crossings, however, the final decision was to be based on selection, timing and river conditions at the time of construction.

15.45 The most important of these crossings will be

15.46 A full camp has been allowed for on each loop other then Loops 9 and 10 which will use local accommodation. The cost estimate allows for four core camps and forward and rear fly camps.

Schedule

15.47 Design works for Stage 5A2 commenced in October 2007, and intended to flow into Stage 5B design as the scope of 5B was confirmed.

15.48 The Stage 5B design effort was expected to last six months based on the scope of work.

Assumptions - Design Engineering

15.49 All Worley Parsons engineering man hour rates are based on current 2008 WorleyParsons rates.

15.50 Manning profile was based on proposed organisation structure for Stage 5B. Manning numbers reflect lessons learned from Stage 5A.

15.51 Duration and man-hours assume design basis was fixed and as such little or no FEED study work will be necessary.

Assumptions - Overheads

15.52 Overhead costs include costs for activities which may be attributed to both Looping and Facilities.

15.53 Overheads costs allow for safety case requirements such as training, GPS in vehicles, etc.

15.54 An insurance cost estimate has been supplied by DBP. This was estimated for the project as a whole and was not broken down into Facilities and Looping.

15.55 An allowance for a personnel retention scheme has been included for the team following the risk assessment. This is to encourage key members to remain with the project as long as necessary.

15.56 Fuel gas costs during shutdown/commissioning periods based on DBP forecast. [DELETED]

CPI Escalation

15.57 DELETED

15.58 The rates applied to labour vary depending on the type of labour under consideration in line with expected market movements. These are inclusive of 3% CPI and are expected to cover total escalation over the duration of the project.

Exchange Rates

15.59 Project budgets were prepared on the basis of projected foreign exchange rates of US$0.875 to AU$1.00, except for the initial 120km of linepipe which was hedged at US$0.75 to AU$1.00, and ¥88.00 to AU$1.00.

Line Pipe

15.60 DELETED

15.61 The procurement of line pipe followed a similar strategy to that used on previous stages with the supplier [DELETED]. However, a 140Km of line pipe has already been ordered [DELETED] for Stage 5A-2 and this manufacture of this pipe commenced in March 2008.

15.62 Shipments of bare line pipe to Malaysia were planned between the months of April and December 2008.

15.63 The overall cost of the pipe supply contract increased due to the sharp increase in ocean freight and raw material prices.

15.64 Coating of the line pipe were to follow a similar arrangement to that used on the previous stages; i.e. coating in Kuantan, Malaysia. [DELETED]

15.65 The initial 140Km was expected to be coated in Kuantan commencing June 2008 and would be followed by the balance of the bare pipe which would be coated progressively. It was anticipated that the final shipment of coated pipe would arrive in Australia in April 2009.

15.66 Total linepipe takeoff including contingency was 443.8km, and allowing for surplus Stage4/5A of 3.1km total procurement under Stage 5B was 440.7km.

Monte Carlo Simulation

15.67 A Monte Carlo probability analysis was performed for the project scope of work to determine project contingencies. The probability analysis examined the quality of estimates, the criteria used in determining the scope of work and the expected variations to each of the components in the build up of the estimates. The collective judgement of personnel involved in similar previous projects formed the basis for probabilities assigned.

Project Schedule

15.68 Engineering design of the Stage 5B scope was to utilise the current team and involve manning up as required in the ensuing months. Design was planned to be substantially completed and most material commitments will be made by 1 September 2008.

15.69 All major equipment and long lead materials commitments were to be made in 2008, in addition to those already committed to in 2007 (under Stage 5A-2). Material deliveries would be timed to enable construction to commence in 2009.

15.70 Initial material purchases were restricted due to unavailability of substantive funds prior to 1 October 2008. This resulted in a substantive number of major equipment and long lead materials being purchased on an "as late as possible basis". It should be recognised that delay to these late orders would almost certainly impact of timely completion and would likely to lead to additional costs for expediting / airfreight as well as claims from the construction contractors.

15.71 Approvals and all risk assessments would be carried out during the design phase in 2008 with final Approval to Construct achieved in late 2008 or early 2009

15.72 Preparation of the construction contract tender for Looping and Facilities during the design phase with schedule pipeline construction award in late August 2008 and Facility construction award in January 2009.

15.73 Construction and commissioning of all loops from March 2009 to April 2010.

15.74 Construction and commissioning of all new Facilities from March 2009 to April 2010.

Payment Schedule

15.75 There were no orders to be placed, or commitments to be made on items prior to the 16th of May 2008, unless a zero cancellation policy, or if there was a defined cancellation charge.

15.76 The project attempted to minimise the number of payments made prior to the 1st of October 2008. This criterion includes staged ordering of equipment.

16. BURRUP EXTENSION PIPELINE ("BEP")

16.1 In order to ensure DBP is able to meet its stage 5B contractual commitments, it needed to consider an additional length of looping on the loop known as loop 0 than what is stated in the earlier section.

16.2 Epic Energy's Burrup Extension Pipeline (BEP) parallels the DBNGP for the first 23km from the North West Shelf Domgas Plant to Mainline Valve No 7 at Cajaput Well before connection to the Pilbara Energy Pipeline which transports gas to Port Headland. The BEP can be readily used as loop of the DBNGP by opening valves at Cajaput Well and on the BEP itself.

16.3 Due to the terrain and heritage issues on the Burrup Peninsula, DBP identified that it would be difficult to construct an additional pipeline in that region, despite the rights which DBP has to do so. It therefore considered it to be highly desirable to reach a commercial arrangement with Epic Energy to utilise the unused capacity in the BEP as a loop of the DBNGP.

16.4 DBP accordingly entered into a long term lease agreement with Epic Energy under which, upon the satisfaction of certain conditions precedent, a lease fee is paid to Epic for the lease of the BEP capacity and DBP assumes operation of the BEP as a loop of the DBNGP.

16.5 DELETED

16.6 DELETED

16.7 DELETED

16.8 DELETED

16.9 DBP notes that the position applicable in Victoria on this issue and that adopted by the AER in its draft Regulatory Reporting Guidelines for Gas Pipeline Service Providers published in May 2004. The application of the Australian Accounting Standards in making determinations on the categorisation of outgoings and liabilities for the purposes of applying the reference tariff principles would encourage a consistent approach by the ERA across its regulated customers.

DBP submits that the BEP lease is an expenditure of a capital nature

16.10 If the proposed investment constitutes the acquisition of a capital nature, it will qualify as a capital expenditure acquired to enable the Service Provider to provide Services, and will therefore be a conforming capital expenditure if it meets the requirements of Rule 79, and the amount of the conforming capital expenditure must be added to the Capital Base. The initial question is therefore whether there is expenditure at all; if so, is it expenditure of a capital nature incurred.

16.11 DBP submits that it is capital expenditure.

16.12 What is acquired is a right, for a periodic rental payment, to utilise and trade 150 TJ/d of capacity in the BEP, with an option (by notice at any time prior to 31 December 2011) to increase that capacity to 400 TJ/d, over a term of 20 years, together with an option to extend the lease for a further period of 40 years.

What is capital expenditure

16.13 In commerce, assets are divided into fixed or capital assets, and current or circulating assets. Fixed or capital assets are intended to be held and used in the business, whereas current or circulating assets are intended to be realised in the course of trading. In this case, the asset is the primary right against Epic to capacity in the pipeline, which is not a right DBP will hold for trading. That is, in turning its asset to account, DBP will not confer on its customers primary rights against Epic by assignments of its primary right - but rather it will grant sub-rights enforceable against DBP. Therefore the primary right has the characteristics of a capital expenditure. The application of the accounting standards reinforce this view.

Accounting Standards

16.14 In economic terms, DBP understands that the periodic rental payment would not include a fee for service, but is restricted to an amortisation of the value of the interest in the pipeline. Operating costs are dealt with elsewhere. The liability for a proportionate amount of the capital expenditure and non-routine maintenance costs is consistent with economic ownership of the interest. Ernst & Young reached the conclusion that the transaction would be treated as a finance lease for accounting purposes, resulting in the present value of the periodic rental payments being treated as a capital expense by DBP.

ESC Regulatory Accounting Information Requirements

16.15 In Victoria, the Essential Services Commission has published Gas Industry Guideline No. 17 "Regulatory Accounting Information Requirements", which makes it clear that in information published to the ESC, a licensee's accounting policies must conform with the Australian Accounting Standards wherever possible, and that in the preparation of regulatory accounting statements, substance is to prevail over form wherever they differ.

16.16 On the basis that it is a capital expenditure item it needs to be included in the capital base. The amount to be included in 2010 is $19.04m ($2008), being the net present value of the lease fee payable to Epic over the term of the lease (applying a discount rate).

16.17 However, DBP advises that, due to an error in the preparation of the access arrangement proposal, the costs associated with this asset were not included in the capital expenditure to be rolled into the opening capital base.

16.18 This amount will need to be included in the opening capital base in response to the draft decision, and appropriate amendments will need to be made to the proposed access arrangement information revision document.

17. PRUDENCY OF PARTICULAR COST INPUTS

17.1 While DBP submits that the preceding chapters contain ample evidence to demonstrate that all of the expenditure associated with the Stages 4, 5A and 5B expansions is expenditure that meets the requirements of Rule 79 (1)(a) (ie it meets the prudency and lowest sustainable costs requirements), there are certain items of expenditure with respect to which, DBP provides some specific additional background information to ensure they can be treated as conforming capital expenditure. This section outlines that specific information in relation to the following items:

(a) The project management fees payable to DBP's project manager for the management of the expansion programs, [DELETED]; and

(b) The capital expenditure made by DBP in constructing the additional assets required to allow the capacity contracted by [DELETED], to be converted to T1 capacity.

Project management fees payable to the expansion project manager

17.2 DELETED

17.3 DELETED

17.4 DLEETED

17.5 The inclusion of fees of this type in expansion project costs has been questioned previously by regulators because:

(a) such fees appear, in the minds of regulators, to be "cost-plus" in nature;

(b) there are no performance or efficiency requirements imposed on the provider of construction services; and

(c) the fees are large in relation to the scale of the project.

17.6 DBP submits that:

(a) insufficient reasoning exists to conclude that these fees do not meet the requirement of Rule 79 of the NGL; and, moreover,

(b) there is evidence to support the conclusion that these fees do meet the requirements of section Rule 79 of the NGL.

The amount must be capital expenditure

17.7 There are several reasons why the amounts recovered by way of a PM Fee and a PMR Fee are capital expenditure.

17.8 Firstly, DBP incurs the WestNet PM Fee in the process of expanding or replacing assets which form the DBNGP, and which are used to provide services to shippers in the future.

17.9 Secondly, DBP incurs the PMR Fee in the process of ensuring WestNet has resources, processes and systems in place to be able to commence the management of a project at relatively short notice. This is particularly relevant in the context of contractual background where shippers can require additional capacity within 24 months of an access request but also where there is significant uncertainty as to when expansions will be required.

17.10 DELETED

The amount must be incurred by a prudent Service Provider acting efficiently

17.11 Concern has been expressed, by the ERA and by others, that project management fees might not reflect amounts incurred by prudent Service Providers acting efficiently because no performance or efficiency requirements were imposed on the provider of construction project management services.

17.12 DBP submits that, [DELETED], the amount of the fees is such that it would be incurred by a prudent Service Provider acting efficiently for the following reasons:

(a) The current owners of the DBNGP comprise DUET (60%), Prime Infrastructure (20%) and Alcoa of Australia (20%). DUET is a major owner of infrastructure assets in Australia but (as with its investment in the DBNGP) it invests as a "passive" owner rather than as an "owner/operator" of assets. DUET does not possess the technical or operational expertise to manage the operation or expansion of pipelines. It therefore relies on others with these skills. Alcoa's investment is primarily aimed at maintaining a secure, reliable and economically efficient supply of gas to its significant downstream operations in the South West of Western Australia. Through WestNet, Prime has experience in the ownership, operation and development of gas pipelines. Accordingly, it is prudent for the ownership consortium of the DBNGP to have relied on the resources and expertise of one of the members of that consortium to provide services relating to the operation and expansion of the pipeline.

(b) DELETED

(c) DELETED

(d) the amount of the PM fee and the PMR Fee is efficient because it covers an expansive range of services provided by WestNet [DELETED] in relation to capacity expansions and capital works. These include all project services, from conceptual design, through FEED studies, planning, construction, commissioning and final delivery of the projects for operation (and all services to support these activities e.g. human resources management, and financial control), are either undertaken directly by WestNet or arranged and managed through contractors that are under the day to day management of WestNet (although contracted by DBP).

(e) the amount is efficient having regard to DBP's commercial arrangements with shippers. Under the Standard Shipper Contracts, DBP has a positive obligation to seek to minimise the capital costs of expansions of the DBNGP. Otherwise, it risks not being able to recover costs from shippers. Therefore DBP is incentivised to ensure that its contractors, including WestNet, do not spend more than amounts that can be recovered from shippers. It should also be noted that under the OSA, it is DBP, not WestNet that approves the budgets for the operation and expansion of the DBNGP. In approving such budgets, DBP must have regard to the limitations on its ability to recover costs. Moreover, WestNet is not able to spend more than 110% of the budget without prior approval of DBP.

(f) the project management fee payable to WestNet is reflective of costs incurred by a prudent Service Provider acting efficiently is the fact that under the OSA, WestNet is incentivised to incur costs efficiently. [DELETED]

(g) DELETED

The amount must be incurred by a prudent Service Provider acting in accordance with accepted good industry practice

17.13 DBP submits that the forecast project management fee is an amount which would be incurred by a prudent Service Provider acting in accordance with accepted good industry practice for the following reasons.

(a) DELETED

(b) Secondly, project management fees are accepted industry practice in the construction industry. This is supported by information received (at this stage, informally) from a number of reputable engineering consulting firms, indicating that the existence of a project management fee in similar infrastructure construction projects, is usual industry practice.

(c) Thirdly, as outlined above, shippers on the DBNGP have, through the tariff adjustment mechanism under the Standard Shipper Contracts, agreed that fees such as the 3% project management fee payable to AAM can be included in the calculation for the adjustment to the tariff payable under these Contracts.

(d) Fourthly, recent market information (which is publicly available) in respect of similar arrangements in place for other infrastructure for the payment of a project management fee indicates that:

(i) it is accepted practice for project management fees to be included in contracts for infrastructure construction; and

(ii) the amount of the fee payable to AAM (that is, 3%) compares favourably with other fees payable in similar circumstances.

17.14 In this regard, DBP refers to two reports prepared by NERA for Jemena Networks as part of the revised access arrangement proposal. The reports are:

(a) A report dated March 2007 called "Outsourcing by Regulated Businesses". A copy is contained in ATTACHMENT 26; and

(b) A report which critiques "Allen Consulting Group's Review of NERA's Benchmarking of Contractors' Margins" prepared in 2007. A copy is contained in ATTACHMENT 22**.**

17.15 A key finding of this report was that prudently incurred outsourcing contracts will generally include a margin on the contractor's directly incurred costs. It was also noted in the report that the payment of such margins is consistent with both economic theory and observed good industry practice and will tend to reflect:

(a) the contractor's ability to provide the service at a lower cost than the purchaser could obtain elsewhere (eg, a return to the 'know how' of the contractor);

(b) the required return on and return of physical and intangible assets employed by the contractor in the provision of the service;

(c) efficiencies on the part of the contractor over the life of the contract (eg, where the contract allows some part of these to be retained by the contractor);

(d) the allowance required to meet the contractor's common costs; and

(e) the allowance required to self insure against the asymmetric risks faced by the contractor.

17.16 The report contains a benchmarking of the margins of various asset managers and argues that the margins of Alinta Asset Management (who, in the case of the DBNGP were removed as asset managers in 2009 as part of the changes to the OSA) should remain as an appropriate benchmark. It concluded that an acceptable range of margins (with a 95% confidence interval for the true population mean) is from 4.3% to 6.7%.

17.17 While the PM Fee and the PMR Fee payable to the Project Manager are not expressed as margins per se, the quantum of the fees effectively fall within this range.

The amount must be incurred by a prudent Service Provider to achieve the lowest sustainable costs of providing the Services

17.18 The reasons outlined above to substantiate the costs as those incurred by a Service Provider acting efficiently apply equally to substantiate the costs as being incurred by a prudent Service Provider to achieve the lowest sustainable costs of providing the Services. A project management fee of the type which DBP proposes to pay to WestNet would be payable by DBP to any manager it appointed to manage a large construction project such as the Stage 5 expansion of the DBP. Furthermore, the 3% fee payable to WestNet compares favourably with the fees that are generally paid to managers of large construction projects.

17.19 DELETED

17.20 DELETED

17.21 DELETED

17.22 DELETED

17.23 DELETED

17.24 DELETED

17.25 DELETED

18. JUSTIFICATION OF THE EXPANSION PROGRAM AGAINST THE CRITERIA IN RULE 79(2) OF THE NGR

18.1 DBP submits that the entire expenditure encompassed by the Stage 4, 5A and 5B expansion programs is conforming capital expenditure in that:

(a) It meets the requirements of Rule 79(1)(a) of the NGR; and

(b) It meets the requirements of Rule 79(1)(b) of the NGR.

18.2 DBP submits that the preceding sections of this submission contain the justification for meeting the requirements of Rule 79(1)(a) of the NGR.

18.3 DBP also submits that there are several ways to justify that the entire expenditure encompassed by the Stage 4, 5A and 5B expansion programs meets the requirements of Rule 79(1)(b) of the NGR.

18.4 Firstly, the entire expenditure encompassed by Stage 4, 5A and 5B expansion programs is expenditure necessary to comply with a regulatory obligation or requirement. In this regard, DBP refers to the submissions made earlier in section 2.

18.5 Secondly, and to the extent that the ERA does not accept this submission in the above paragraph, DBP submits that the entire expenditure encompassed by Stage 4, 5A and 5B expansion programs meets the requirements of Rule 79(2)(a) of the NGR – ie the overall economic value of the expenditure is positive.

18.6 In this regard, DBP refers the ERA to its submission earlier on in paragraphs 3.19 to 3.26.

18.7 DELETED

18.8 DELETED

18.9 DELETED

18.10 DELETED

18.11 To the extent that the ERA does not accept any of the above bases for justifying why the expenditure meets the requirements of Rule 79(2) of the NGR, DBP submits that:

(a) in relation to the expenditure incurred for the Stage 4 project:

(i) The initial $400million ($2004) of expenditure incurred in respect of this project is a distinct item of expenditure which is consistent with the requirements of Rule 79(2)(c)(iii) of the NGR; and

(ii) The remainder of the expenditure incurred in relation to Stage 4 is also a distinct item of expenditure, which meets the requirements of Rule 79(2)(a) of the NGR;

(b) In relation to the expenditure incurred for the Stage 5A project:

(i) The expenditure incurred as a result of changing the gas quality assumption for the design of the DBNGP is justified under Rule 79(2)(c)(iii) or (iv) of the NGR; and

(ii) The remainder of the expenditure incurred in relation to Stage 5A is also a distinct item of expenditure, which meets the requirements of Rule 79(2)(a) of the NGR for the reasons outlined in the Marsden Jacob & Associates report; and

(c) DELETED

ATTACHMENT 1 STATEMENTS ON SYSTEM WIDE BENEFITS OF THE PROPOSED EXPANSION PROGRAM

Transcript

Station: ABC 720 PERTH **Date:** 31/08/2004

Program: 12:00 NEWS **Time:** 12:03 PM

Compere: NEWSREADER **Summary ID:** P00015070083

Item: ENERGY MINISTER ERIC RIPPER SAYS SUCCESSFUL SALE OF DAMPIER TO BUNBURY GAS PIPELINE WILL LEAD TO LOWER ENERGY COSTS FOR CONSUMERS.
INTV: ERIC RIPPER, ENERGY MINISTER

Demographics:	Male 16+	Female 16+	All people	Abs	GBs
	18000	9000	28000	8000	15000

NEWSREADER: The Energy Minister Eric Ripper says the successful sale of the Dampier to Bunbury gas pipeline will lead to lower energy costs for consumers. A consortium comprising DUET, Alinta and Alcoa has bid $1.86 billion for the pipeline. Alinta Chief Executive Bob Browning says the deal should be finalised within eight weeks and work will begin immediately to expand the line to help meet the States' growing energy demands. Mr Ripper says the sale is good news for the State.

ERIC RIPPER: Well, the sale and expansion of the pipeline is very important to promote competition in our electricity market and competition in our electricity market will create downward pressure on prices, so this is a very important issue for both the security of our electricity supply and for competition in our electricity market with consequent benefits on ultimate prices.

* * END * *

STATEMENT OF THEN ENERGY MINISTER, MR E RIPPER

Statement Released: 25-Oct-2004
Portfolio: Deputy Premier, Energy

Gas contract secures long-term energy supplies

25/10/04

Deputy Premier and Energy Minister Eric Ripper has given approval for Western Power to enter into a billion-dollar contract to protect the State's energy security for the next 25 years.

Mr Ripper said the gas transport contract allowed Western Power to secure the gas supplies it needed to generate more electricity for the growing State economy.

He said the agreement would clear the way for the imminent sale of the Dampier-to-Bunbury natural gas pipeline - which had been in receivership since April 2004 - to be concluded.

"Sale of the pipeline will mean the long-awaited expansion can occur, delivering more gas to meet the needs of a growing State," the Deputy Premier said.

"It will mean that, for the first time since the privatisation of the pipeline in 1998, we can say that the State's long-term energy needs have been secured.

"Importantly, Western Power has negotiated a gas transport contract that is in its best commercial interests.

"I could not have accepted an arrangement that disadvantaged Western Power as it faces an increasingly competitive market environment."

Mr Ripper said the Government was close to concluding its financial assistance agreement with the pipeline's prospective new owners.

"The transaction will attract stamp duty, which must be paid in full," he said.

"However, the Government has secured guaranteed, timely expansion of the pipeline through the provision of financial assistance.

"Expansion of the pipeline is in the best interests of the State. An affordable and reliable electricity supply and the development of gas powered projects in the South-West depend on it."

STATEMENT FROM ENERGY MINISTER

Statement Released: 27-Oct-2004
Portfolio: Deputy Premier, Energy

Pipeline sale a boost for State economy

27/10/04

Energy Minister Eric Ripper has hailed the sale of the Dampier-to-Bunbury natural gas pipeline as a major shot in the arm for the Western Australian economy.

Mr Ripper said the sale to a credible, financially stable owner meant the long awaited expansion could go ahead, providing gas for electricity generation and for major industrial projects.

"It gives local businesses and new investors confidence that the South-West of WA will have the gas supplies needed to power economic growth well into the future," he said.

"Without the sale of the pipeline and its timely expansion, WA could have faced years of economic uncertainty with unreliable electricity and stalled industrial projects."

The gas pipeline has been sold to a consortium of Diversified Utility and Energy Trusts (DUET), Alcoa and Alinta.

"It is the most important strategic issue that has faced the Gallop Government since its election to office," the Minister said.

"We have always said a successful commercial outcome was the best solution to the impasse with the previous owner about independently regulated tariffs and the owners refusal to undertake expansion.

"The pipeline saga is an important illustration of the pitfalls of privatisation, particularly of strategic assets."

Mr Ripper said the Government had committed $88million to the timely expansion of the pipeline.

"The consortium will pay stamp duty in full. However, the Government has secured guaranteed, timely expansion of the pipeline through the provision of financial assistance to an equivalent amount," he said.

"The assistance will be in the form of a 99-year loan, which may convert to a non-repayable grant at the request of the consortium if the expansion commitments are satisfied.

"This is an important investment in long-term energy security for WA."

The Minister said the successful sale meant the Government had maintained the integrity of the Regulatory system by resisting calls to compromise State law and Federal agreements by interfering in the Regulator's tariff decisions.

"Setting tariffs by political fiat in order to prop up the previous pipeline owner financially, would have signalled to investors that the WA Government has no respect for the law or proper processes," he said.

The sale of the pipeline follows the finalisation of a billion dollar gas transport contract between Western Power and the new owners earlier this week.

The 1,300km pipeline was privatised by the Court Government in 1998 for $2.4billion. The pipeline was placed in receivership in April this year.

ATTACHMENT 2 EXPLANATION OF STAGE 4 COMPRESSION

This attachment outlines in detail the extent of the modifications to be undertaken at each of the compressor station sites as part of Stage 4 (Stages 4A-C and 4E-H) It should be noted the compressor station modifications contain a number of activities that are common to all sites – these modifications are identified initially. The attachment then identifies the additional items of work that are required to be performed to cater for site specific differences. (An early section of the submission outlines the scope of work for looping.)

COMMON STATION MODIFICATIONS

Mechanical

- Supply and install Solar Turbines 10 MW MARS 100 turbine / C652 (at CS10, Solar Taurus 70) compressor unit complete with on skid enclosure;
- Supply and install remote lube oil cooler for new turbine /compressor unit;
- Supply and install fuel gas filter rack for new turbine / compressor unit;
- Supply and install below ground waste water transfer tank;
- Supply and install new double skinned above ground lube oil storage / waste water collection tank complete with vacuum transfer pump for new turbine / compressor unit;
- Supply and install air inlet filter / ducting for new turbine / compressor unit; and
- Supply and install exhaust silencer / ducting for new turbine / compressor unit.

Piping

Compressor Process Piping

- Supply and install suction and discharge piping for new compressor unit;
- Supply and install new check valve in the station header between tie-in for new compressor suction and the station after cooler; and
- Supply and install recycle piping for new compressor.

Waste Water Piping

- Supply and install waste water drain piping between new compressor enclosure and new transfer / collection tanks.

Lube Oil Piping

- Supply and install lube oil piping from turbine / compressor unit to lube oil coolers.

Fuel Gas Piping

- Supply and install fuel gas piping (including filter and PRV’s) to new turbine.

Instrument Gas Piping

- Supply and install instrument gas pressure reduction skid for the new turbine / compressor installation; and
- Supply and install instrument gas piping to instrument gas consumer points associated with the new turbine / compressor unit installation.

CIVIL AND CONCRETE

- Clear ground, prepare finished ground levels and excavate / backfill for new turbine / compressor installation;
- Install concrete footings for new turbine / compressor and enclosure, turbine inlet filter/ducting, turbine exhaust silencer, enclosure ventilation inlet filter / ducting and enclosure ventilation exhaust;
- Install concrete ground slab apron around new turbine / compressor enclosure;
- Install concrete raft footing for new turbine / compressor lube oil cooler;
- Install concrete raft footing for the fuel gas skid associated with the new turbine;
- Install concrete raft footing for the instrument gas skid associated with the new turbine / compressor installation;
- Install concrete footings for pipe supports, valve platform and pipe crossovers for process gas piping associated with the new compressor installation;
- Excavate and backfill trenches for piping, cable ducts and pits, and electrical, instrument and control cabling; and
- Install concrete footings for off site fabricated 'local' unit switchgear and control room

STRUCTURAL

- Supply and install new offsite fabricated 'local' unit switchgear and control room;
- Supply and install structural steel to support turbine inlet filter and enclosure ventilation inlet filter associated with the new turbine / compressor installation; and
- Supply and install structural steel to support the lube oil cooler associated with the new turbine / compressor installation.

ELECTRICAL

New Unit MCC

Supply and install new Unit MCC c/w with the following drives:

- New compressor unit starter motor feeder and Solar supplied VFD;
- New compressor enclosure DOL ventilation fans;
- New compressor unit lube oil cooler fans;
- New compressor unit lube oil pump;
- New compressor lube oil sump decant pump;
- Miscellaneous ventilation/air conditioner feeders; and
- New compressor enclosure lighting and small power panel feeder.

Cabling, Ducts and Ladders

- Supply and install power, control and instrumentation cabling to:
- New compressor unit and ancillary drives;
- Supply and install A/G cable ladder system within switchgear / control room; and
- Supply and install U/G cable duct system to the new compressor enclosure.

24V DC Power Supply

- Install Solar supplied 24V DC UPS system in switchgear/control room;
- Supply and install new compressor unit 24V DC distribution board; and
- Modify existing station 24V DC system to accommodate new equipment

110V DC Power Supply

- Modify existing 110V DC power supply system to provide a feeder to the new compressor emergency lube oil pump

Lighting and Small Power

- Supply and install new turbine / compressor installation lighting and small power distribution panel
- Supply and install lighting and small power to:
- New turbine / compressor enclosure and surrounds.

Earthing and Cathodic Protection

- Modify existing cathodic protection TRU to provide new circuits
- Supply and install cathodic protection cables and test points
- Supply and install new earthing and lightning protection to:
- New turbine / compressor enclosure and surrounds

Instrumentation and Control Systems

- Supply and install pressure, differential pressure, temperature and level transmitters, indicators and switches to the new compressor unit off skid piping and ancillary equipment;
- Supply and install new ultrasonic flow meter in pipeline at entrance to compressor station;
- Supply and install additional hardware and modify existing unit control systems to suit installation of additional turbine / compressor unit; and
- Supply and install additional ACF/ load shed PLC hardware and cabinet, to be integrated with existing ACF / load shed PLC.
- SCADA and Telecommunications
- Modify and upgrade existing SCADA system to suit installation of additional compressor unit and associated station equipment; and
- Provide additional Public Address (PA) and telephone for new facilities.

Fire and Gas Systems

- Supply and install new Fire and Gas system for new turbine / compressor unit; and
- Supply and install new Fire and Gas system for unit switchgear / control room.

COMPRESSOR STATION CS1

PIPING

Vent Piping

- Modify station venting system to a common station venting system which includes:
- Supply and installation of a station vent header including vent stack and silencer;
- Supply and install piping to connect the existing Unit 1 and Unit 2 turbine / compressor installation to the new station vent header;
- Replace existing vent isolation valves with plug valves; and
- Supply and install vent piping from new compressor unit suction/discharge installation to the new station vent header.

CIVIL AND CONCRETE

- Realign and Chipseal surface the road running along the east side of new compressor/turbine installation plus provide a Chipseal surface road to the compressor enclosure turbine removal access door;
- Install Gravel surface road along the west side of new compressor / turbine installation; and
- Install concrete footings for new station vent stack and silencer.

Electrical

MDB – A

- Modify existing MDB-A to suit new compressor unit 400A MCC feeder
- Instrumentation and Control Systems
- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

COMPRESSOR STATIONS CS2, CS4 AND CS7

MECHANICAL

- Remove existing 230kW Waukesha powered GEA and replace with upgraded 400kW GEA; and
- Install additional 400kW GEA at CS7 only.

PIPING

Vent Piping

- Supply and install vent piping from new compressor unit suction and discharge piping to existing vent piping running from the Unit 1 compressor installation.

Fuel Gas Piping

- Supply and install increased capacity fuel gas piping and Regulators to suit upgraded 400kW GEA(s).
- Civil and Concrete
- Demolish concrete footings for existing 230kW Waukesha powered GEA / remote radiator and install new concrete footings for a packaged 400kW GEA;
- Install concrete footings for an additional 400kW GEA to CS7 only;
- Install a Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door;
- Install Gravel surface roads along the north and west sides of new turbine / compressor installation; and
- Re-align airstrip to obtain adequate clearance from new turbine / compressor installation.

ELECTRICAL

Power Generation

- Supply and install 400kW GEAs and associated remote control panels; and
- Supply and install load banks and associated cabling.

MDB – A

- Modify existing MDB-A to suit 400kW GEA power and controls;
- Modify existing MDB-A to suit GEA load bank starters; and
- Modify existing MDB-A to suit new 400A Unit MCC feeder.

Earthing and Cathodic Protection

- Supply and install new earthing and lightning protection to new 400kW GEA enclosure.
- Instrumentation and Control Systems
- Supply and install new station control panel incorporating the following:

- New SESD and MESD systems;
- New station valve control system; and
- New station PLC and HMI.

Fire and Gas Systems

- Modify existing Fire and Gas systems to suit the following:
  - Deletion of 230kW Waukesha powered GEA; and
  - Installation of new 400kW GEA c/w unitised Fire and Gas system;

Demolition and Isolation

- Carry out electrical demolition work to suit:
  - Removal of 230kW GEA and associated control panels; and
  - Removal of entire existing station control panel.

COMPRESSOR STATION CS3

- Supply and install turbocharger units to GEA 1 and GEA 2 (upgrade to 500kW).

Piping

Vent Piping

- Modify station venting system to a common station venting system which includes:
  - Supply and installation of a station vent header including vent stack and silencer;
  - Supply and install piping to connect the existing Unit 1 and Unit 2 turbine / compressor installation to the new station vent header;
  - Replace existing vent isolation valves with plug valves; and
  - Supply and install vent piping from new compressor unit suction/discharge installation to the new station vent header.

CIVIL AND CONCRETE

- Realign and Chipseal surface the road running along the east side of new compressor/turbine installation plus provide a Chipseal surface road to the compressor enclosure turbine removal access door;
- Install Gravel surface road along the west side of new compressor/turbine installation; and
- Install concrete footings for new station vent stack and silencer.

ELECTRICAL

MDB – A

- Modify existing MDB-A to suit 500kW GEA power and controls; and
- Modify existing MDB-A to suit new compressor unit 400A MCC feeder

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

COMPRESSOR STATION CS6

PIPING

Vent Piping

- Supply and install vent piping from new compressor unit suction/discharge piping to existing vent piping running from the Unit 1 installation.

CIVIL AND CONCRETE

- Install Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door; and
- Install Gravel surface roads along the north and west sides of new turbine / compressor installation.

ELECTRICAL

MDBs

- Modify existing MDB to suit new 400A Unit MCC feeder.

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI with full Modbus connectivity, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

COMPRESSOR STATION CS9

PIPING

Compressor Process Piping

- Supply and install new underground station header;
- Tie-in existing Unit 1 compressor discharge piping into the new underground station header; and
- Install isolation spectacle blinds on the Unit 1 compressor unit suction and discharge lines.

Vent Piping

- Supply and install vent piping from new compressor unit suction/discharge piping to the station vent header.

CIVIL AND CONCRETE

- Install Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door; and
- Install Gravel surface roads along the south and west sides of new compressor/turbine installation.

ELECTRICAL

MDBs

- Modify existing GEA1 and 2 MDBs to suit new 400A Unit MCC feeders; and
- Modify existing GEA1 and GEA 2 MDBs to make earth leakage protection operational

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI with full Modbus connectivity, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

ATTACHMENT 3 KIMBER CONSULTANTS REPORT

See attached

ATTACHMENT 4 DELETED

ATTACHMENT 5 DELETED

ATTACHMENT 6 DELETED

ATTACHMENT 7 DELETED

ATTACHMENT 8 DELETED

ATTACHMENT 9 DELETED

ATTACHMENT 10 DELETED

ATTACHMENT 11 DELETED

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ATTACHMENT 22 NERA ALLENS CONSULTING GROUP REPORT ON BENCHMARKING OF ASSET MANAGEMENT FEES

See attached

ATTACHMENT 23 DELETED

ATTACHMENT 24 DELETED

ATTACHMENT 25 DELETED

ATTACHMENT 26 OUTSOURCING BY REGULATED BUSINESSES

See attached