GOLDFIELDS GAS PIPELINE

PROPOSED REVISIONS TO ACCESS ARRANGEMENT INFORMATION

APPROVED BY
ECONOMIC REGULATION AUTHORITY

5 August 2010

AS AMENDED BY THE
WESTERN AUSTRALIAN ELECTRICITY REVIEW BOARD

30 March 2012

GOLDFIELDS GAS PIPELINE
CONTACT DETAILS

Goldfields Gas Transmission Pty. Ltd.
ACN 004 273 241

Principal Office: **Level 5**
Eastpoint Plaza
233 Adelaide Terrace
Perth
Western Australia 6000

Telephone: **+61 8 6189 4300**

Facsimile: **+61 8 6189 4349**

Contacts: **Steve Lewis,** General Manager

Suzy Tasnady, Regulatory Manager

1 INTRODUCTION

This Access Arrangement Information (AAI) is submitted by Goldfields Gas Transmission Pty Ltd (GGT), the Service Provider for the Goldfields Gas Pipeline (GGP). This AAI incorporates the required amendments in the Economic Regulation Authority Further Final Decision on GGT's Proposed Revisions to the Access Arrangement dated 5 August 2010 and the Final Decision by the Western Australian Electricity Review Board dated 30 March 2012 for the Covered Pipeline. A detailed description and map of the Covered Pipeline is set out in Section 12.

Projections in this AAI are based on a number of assumptions. GGT does not make any representation or warranty as to the accuracy of the assumptions.

Years shown in the tables refer to calendar years. The totals in some tables in this AAI may not sum due to rounding.

2 TOTAL REVENUE

The Total Revenue for the Covered Pipeline has been determined on an annual basis using the cost of service method as permitted under the Code. Total Revenue is equal to the total cost of providing all Services on the Covered Pipeline, which is the sum of:

- a return on the Capital Base (including on New Facilities Investment forecast for the Access Arrangement Period), calculated using the proposed Rate of Return;
- Depreciation; and
- Non Capital costs, being the operating, maintenance and other non-capital costs incurred in providing Services.

The Total Revenue for the Covered Pipeline has been derived on a nominal basis as described in section 8.5A(a) of the Code.

The total cost of providing all Services for the Covered Pipeline for the period 20 August 2010 to 31 December 2014 is shown in Table 1.

Table 1 : Total Revenue ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	**2011**	**2012**	**2013**	**2014**
Non Capital Cost	11.0	26.1	27.0	28.9	30.8
Over Depreciation	-0.4	0.0	0.0	0.0	0.0
Depreciation	3.9	11.3	11.9	12.2	12.3
Return on Plant Value	16.3	45.8	45.5	44.7	43.7
Return on Non-Depreciable	0.2	0.6	0.6	0.5	0.5
Total Cost of Service	31.0	83.8	85.0	86.2	87.3

3 CAPITAL BASE

The Initial Capital Base of the Covered Pipeline (at 31 December 1999) is $513.7 million. The Initial Capital Base has been rolled forward to 19 August 2010 to reflect Depreciation as forecast under the approved Access Arrangement, the actual capital cost of New Facilities Investment which occurred during the Access Arrangement Period from 2000 – 19 August 2010

For the purpose of calculating Depreciation, the assets which form the Capital Base of the Covered Pipeline have been allocated into the asset classes shown in Table 3. The economic lives for the various asset classes are shown in Table 5.

Changes in the value of the asset base from 2000 to 19 August 2010 are shown in Table 2.

Table 2 : GGP Capital Base roll forward 2000- 19 August 2010 ($m, nominal)

	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010 (1 Jan to 19 Aug 2010)**
Opening asset value	513.7	507.3	505.8	495.5	496.1	490.3	480.2	471.0	461.0	450.3	442.6
Capital expenditure	3.6	8.4	1.1	10.1	6.1	1.5	2.1	1.8	1.7	3.3	5.5
Change in working capital	0.3	0.7	-0.7	1.4	-0.7	-0.1	0.3	0.0	-0.2	0.2	1.3
Depreciation	10.4	10.6	10.8	10.9	11.2	11.4	11.6	11.9	12.1	11.6	6.8
Adjustment for over depreciation										0.4	
Closing asset value	**507.3**	**505.8**	**495.5**	**496.1**	**490.3**	**480.2**	**471.0**	**461.0**	**450.3**	**442.6**	**442.6**

Table 3 : GGP Initial Capital Base ($m, 19 August 2010)

Asset class	**Value in Initial Capital Base**	**Value as at 19 August 2010**
Pipeline and laterals	438.7	368.7
Mainline valve and scraper stations	9.2	7.1
Compressor stations	41.6	47.1
Receipt and delivery point facilities	1.5	2.1
SCADA and communications	10.1	2.2
Cathodic protection	1.8	1.9
Maintenance bases and depots	7.7	6.1
Remote accommodation	0.0	0.0
Other assets	0.4	3.9
Sub Total	511.1	439.1
Linepack	1.1	1.1
Working capital	1.5	3.0
Initial Capital Base	**513.7**	N/A
Capital Base	N/A	**442.6***

* Minor difference compared to addition of values in table due to rounding

4 FORECAST NEW FACILITIES INVESTMENT

Minor capital expenditure is required during the life of any pipeline. This capital expenditure covers replacement of miscellaneous capital equipment and enhancements of peripheral and utility systems and equipment. Forecast amounts are also included for system upgrades to meet contractual commitments on the Covered Pipeline and to replace aged facilities.

No expansion or extension related capital expenditure is forecast on the Covered Pipeline during the Access Arrangement Period.

Forecast Capital expenditure for the Access Arrangement period is as shown in Table 4.

Table 4 : Forecast Capital Expenditure ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	**2011**	**2012**	**2013**	**2014**
Pipeline and laterals	0.0	0.0	0.0	0.0	0.0
Mainline valve and scraper stations	0.0	0.0	0.0	0.0	0.0
Compressor stations	1.2	3.5	0.8	0.9	0.9
Receipt and delivery point facilities	0.0	0.1	0.1	0.1	0.1
SCADA and communications	0.2	1.9	1.9	0.5	0.5
Cathodic protection	0.5	0.0	0.0	0.0	0.0
Maintenance bases and depots	0.0	0.0	0.0	0.0	0.0
Remote Accommodation	0.0	1.4	0.0	0.0	0.0
Other assets	1.3	2.3	0.8	1.2	0.6
Total	**3.2**	**9.1**	**3.7**	**2.7**	**2.2**

5 DEPRECIATION

The assets comprising the Capital Base for the Covered Pipeline have been depreciated from 2000 to 2009 by applying the straight line method.

The asset lives and remaining lives as at 31 December 2009 are shown in Table 5.

Table 5 : Asset lives and remaining lives

Asset class	Life of new assets (years)	Remaining life of initial assets (years)
Pipeline and laterals	70	54.5
Mainline valve and scraper stations	50	34.5
Compressor stations	30	14.5
Receipt and delivery point facilities	30	14.5
SCADA and communications	10	0
Cathodic protection	15	0
Maintenance bases and depots	50	34.5
Remote accommodation	15	N/A
Other assets	10	0

The forecast amounts of Depreciation for each class of assets are shown in Table 6.

Table 6 : Forecast Depreciation ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	**2011**	**2012**	**2013**	**2014**
Pipeline and laterals	2.5	6.8	6.8	6.8	6.8
Mainline valve and scraper stations	0.1	0.2	0.2	0.2	0.2
Compressor stations	1.0	2.7	2.9	2.9	2.9
Receipt and delivery point facilities	0.0	0.1	0.1	0.1	0.1
SCADA and communications	0.1	0.3	0.5	0.7	0.7
Cathodic protection and remote accommodation	0.0	0.2	0.3	0.3	0.3
Maintenance bases and depots	0.1	0.2	0.2	0.2	0.2
Other assets	0.1	0.7	0.9	1.0	1.0
Total	**3.9**	**11.3**	**11.9**	**12.2**	**12.3**

6 FORECAST ROLL FORWARD OF CAPITAL BASE 20 August 2010 TO 2014

The forecast movements in the capital base from 20 August 2010 to 2014 are shown in Table 7:

Table 7 : GGP Capital Base roll forward 2010- 2014 ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	**2011**	**2012**	**2013**	**2014**
Opening asset value	442.6	442.6	440.0	431.3	421.9
Capital expenditure	3.2	9.1	3.7	2.7	2.2
Change in working capital	0.8	-0.4	-0.6	0.1	0.2
Depreciation	3.9	11.3	11.9	12.2	12.3
Closing asset value	**442.6**	**440.0**	**431.3**	**421.9**	**412.0**

Closing value of working capital	1.8	4.3	3.8	3.9	4.1

7 RATE OF RETURN

The Rate of Return used for the calculation of Total Revenue is derived as an average of the cost of equity and the cost of debt, each cost being weighted, as appropriate, by the contribution of equity or debt to total financing. The cost of equity is determined using the CAPM. The cost of debt is the sum of the nominal risk free rate of return and a cost of debit margin.

The parameter values applied in determining the Rate of Return are set out in Table 8.

Table 8 : Parameter values for determination of a Rate of Return for the GGP

Parameter	Lo	Hi
Nominal risk free rate (Rfn)	5.79%	5.79%
Real risk free rate (Rfr)	3.21%	3.21%
Inflation Rate (I)	2.50%	2.50%
Debt Proportion (D)	60.00%	60.00%
Equity Proportion (E)	40.00%	40.00%
Cost of Debt; Debt Risk Premium (Drp) (BBB+)	2.83%	2.83%
Cost of Debt; Debt Issuing Cost (Disc)	0.125%	0.125%
Cost of Debt; Risk Margin (DRm)	2.955%	2.955%
Australian Market Risk Premium (Rp)	5.00%	7.0%
Equity beta	0.80	1.00
Corporate Tax Rate (T)	30.00%	30.00%
Franking Credit (g)	0.81	0.37
Nominal Cost of Debt (DPn)	8.75%	8.75%
Real Cost of Debt (DPr)	6.09%	6.09%
Nominal Pre Tax Cost of Equity (EPn)	10.38%	15.77%
Real Pre Tax Cost of Equity (EPr)	7.69%	12.95%
Nominal After Tax Cost of Equity (EAn)	9.79%	12.79%
Real After Tax Cost of Equity (EAr)	7.11%	10.04%

Table 9 shows the range of Rate of Return value derived from these parameters.

Table 9 : Range of pre-tax nominal rate of return

Parameter	Lo	Hi	Lo + 10%	Hi - 10%	Mid of Range
WACC Debt; Pre-tax Officer (Market Practice or Forward Transformation)					
Nominal Pre Tax WACC (WPn)	9.40%	11.56%	9.62%	11.34%	10.48%
Real Pre Tax WACC (WPr)	6.73%	8.83%	6.94%	8.62%	7.78%
WACC; After-tax Vanilla					
Nominal After Tax WACC (WAn)	9.16%	10.36%	9.28%	10.24%	9.76%
Real After Tax WACC (WAr)	6.50%	7.67%	6.62%	7.55%	7.09%

A pre-tax nominal rate of return of 10.48%, being a value within the range defined by these parameter values, was used in determining the Total Revenue.

8 NON CAPITAL COSTS

Non Capital costs are shown in two major categories: 'Operating & Maintenance and Administration & General' and 'Corporate Overheads'.

'Operating & Maintenance' costs are those incurred in the operation and maintenance of the Covered Pipeline. They include the costs of direct operations, operations support, direct engineering support, pipeline maintenance and easement management.

'Administration & General' costs are those incurred in the management of the Covered Pipeline, including the management of legal and regulatory matters directly related to the covered pipeline, public relations, communications leases, commercial management, insurance, support to direct operations and accounting. Administration and General Costs include an allowance for insurance and self insurance, together with amounts for commercial activities including management of the GGPJV, and negotiation and administration of customer contracts.

'Corporate Overheads' costs include costs incurred by the GGT Joint Venture participants in owning and managing their interests in the Joint Venture and the ownership of the GGP, including provision of Services. These costs include costs related to corporate functions undertaken by APA Group, such as IT, human relations, company secretarial services, finance, commercial services, engineering support, legal and also the costs associated with the operation of an ASX listed company. These costs also include increased superannuation payments required to address issues related to the global financial crisis.

Costs arising from asymmetric risks faced by the Covered Pipeline (risks where the distribution of expected returns is skewed or truncated) have not been included in the calculation of Total Revenue. The costs of asymmetric risk are separate to the costs of symmetric risk, which are reflected in the WACC when using the Capital Asset Pricing Model.

Consistent with the nature of the business, GGT's costs are largely fixed in nature. No costs vary directly with the volume of gas transported through the Pipeline. System use gas, in the order of 480 - 500 TJ per year, is provided by shippers.

For the Covered Pipeline, forecast Non Capital costs are as shown in Table 10.

Table 10 : Non Capital Costs ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	**2011**	**2012**	**2013**	**2014**
Operating & Maintenance and Administration & General	8.9	20.3	21.2	23.0	24.8
Corporate Overheads	2.1	5.8	5.8	5.9	6.0
Asymmetric Risk	0.0	0.0	0.0	0.0	0.0
Total	**11.0**	**26.1**	**27.0**	**28.9**	**30.8**

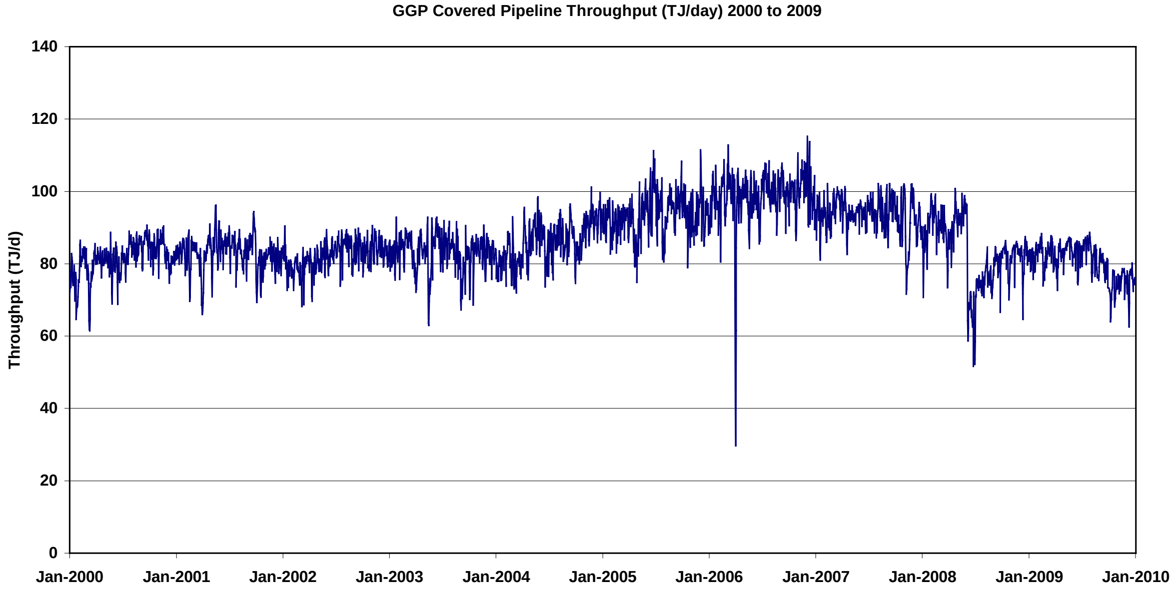
9 VOLUMES

Table 11 shows the historical average annual throughput, reflecting the composite load factor of the currently contracted Users.

Table 11 : Historical Volumes

Historical	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Average daily Throughput (TJ/day)	81.4	83.0	82.2	83.3	86.1	95.8	101.2	96.2	87.1	86.4
Total Annual Throughput (PJ)	29.8	30.3	30.0	30.4	31.5	35.0	36.9	35.1	31.9	31.5

Peak demand and load profile information is provided in graphical form below.



The current capacity of the Covered Pipeline is 109 TJ/day for the current load distribution.

The Covered Pipeline is currently contracted near capacity, with an average of 3.81 TJ/day available over the Access Arrangement Period for provision of the Reference Service as at 1 January 2010.

The forecast peak MDQ and average throughput (terajoules per day) for the Covered Pipeline are shown in Table 12.

Table 12: Volume Forecasts TJ/D

Forecast	**2010**	**2011**	**2012**	**2013**	**2014**
Capacity (TJ/day)	109.9	108.6	108.5	108.9	109.0
Contracted capacity (MDQ, TJ/day)	106.65	105.34	105.26	105.64	105.71
Available capacity (MDQ, TJ/day)	3.81	3.81	3.81	3.81	3.81
Total contracted and available capacity (MDQ, TJ/day)	110.46	109.15	109.07	109.45	109.52
Average daily throughput (TJ/day)	90.7	89.5	89.4	89.7	89.7
Total throughput (PJ)	20 Aug to 31 Dec 2010 12.2	32.7	32.7	32.7	32.8

10 REFERENCE TARIFF AND COST ALLOCATION

10.1 Reference Tariff Structure

There is one Reference Service offered under the Access Arrangement. That service is a Firm Service. The Reference Service is offered for the forecast Available Capacity as shown in Table 12.

The Reference Tariff for the Firm Service has three components which have been designed to broadly reflect the fixed and variable components of transportation costs through the Covered Pipeline.

The three components of the Reference Tariff are:

- Toll Charge (expressed in $/GJ MDQ);
- Capacity Reservation Charge (expressed in $/GJ MDQ km); and
- Throughput Charge (expressed in $/GJ throughput km).

The Reference Service Revenue is allocated to the Toll Charge, the Capacity Reservation Charge and the Throughput Charge in the proportions shown in Table 13.

Table 13 : Reference Tariff Structure

Tariff component	**Proportion**
Toll Charge	11.3%
Capacity Reservation Charge	72.2%
Throughput Charge	16.5%

10.2 Cost Allocation

The Reference Tariff is calculated according to a cost allocation methodology consistent with section 8.38 of the Code. Under this methodology, the Reference Tariff is designed to recover:

- that portion of the Total Revenue that reflects costs incurred that are directly attributable to the Reference Service; and
- that portion of the Total Revenue that reflects costs incurred that are attributable to providing the Reference Service jointly with other Services, with this share determined in accordance with a methodology that meets the objectives in section 8.1 and is otherwise fair and reasonable.

- Capital costs, operating and maintenance costs, corporate overheads and administrative and general costs are allocated to the Reference and Non-Reference Services pro rata on the pipeline capacity applicable to each service.

The portion of Total Revenue allocated to the Reference Service (the **Reference Service Revenue**) is shown in Table 14.

Table 14 : Total Revenue ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	2011	2012	2013	2014
Total Cost of Service	31.0	83.8	85.0	86.2	87.3

The present value of the Reference Service Revenue (using a discount rate equal to a pre-tax nominal Rate of Return of 10.48%) is $288.3 million at 20 August 2010.

10.3 Derivation of Reference Tariffs

The Reference Tariff has been designed to recover the Reference Service Revenue as described above in section 10.2.

The Reference Tariff is derived so that the present value of the forecast annual revenue (obtained by applying the Reference Tariff to the forecast volumes for the Reference Service) is $288.3 million.

This forecast annual revenue to be recovered from providing the Reference Service is shown in Table 15.

Table 15 : Annual Revenue from Reference Tariff ($m, nominal)

	2010 (20 Aug to 31 Dec 2010)	2011	2012	2013	2014
Revenue	31.4	85.6	85.7	85.9	85.9

10.4 Incentive Mechanism

Reference Tariffs are determined for the whole Access Arrangement Period to follow a path forecast to deliver the Reference Service Revenue. This form of regulation provides an incentive to GGP as follows:

- the level of the Reference Tariff is designed to enable GGT to develop the market for the Reference Service and other services as GGT will retain for the Access Arrangement Period the benefit of volumes in excess of those forecast; and
- the prospect of retaining improved returns for the Access Arrangement Period provides an incentive to GGT to minimise the cost of providing Services.

10.5 Other Revenue

The Reference Tariff has been designed to recover the Reference Service Revenue. No allowance has been made for other revenue that may accrue from any other charges payable by Users for the Reference Service as this revenue is not expected to be material. Other charges include, but are not limited to, used gas charges, supplementary quantity option charge and charges payable in respect of receipt points and delivery points such as the connection charge.

11 KEY PERFORMANCE INDICATORS

Efficient Costs and Performance Measures for Pipelines

11.1 Efficient Costs

Section 8.1 (a) of the Code provides that a Service Provider's Reference Tariff and Reference Tariff Policy should be designed to provide the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient cost of delivering the Reference Service.

Section 8.37 of the Code defines efficient costs as those incurred by a prudent Service provider acting efficiently, in accordance with accepted and good industry practice to achieve the lowest sustainable cost of delivering the Reference Service.

11.2 Issues on Performance Measures and Benchmarking of Transmission Pipelines

(a) Differences in pipeline characteristics

It is important to recognise the limitations of benchmarking. The numerous variables that can and do affect costs means that benchmarking can only provide a broad indication of whether a particular pipeline's costs lie within the range of possible efficient costs.

There is a difficulty in "normalising" pipelines to yield meaningful benchmarking comparisons due to differences in the following pipeline characteristics:

- pipeline distance
- pipeline diameter
- pipeline remoteness
- pipeline age and condition
- operational characteristics such as the number of compressors, receipt points and delivery points
- markets served
- natural and man-made environment through which the pipeline passes.

Any comparisons involving the GGP should take account of the following factors:

- Some operating cost items such as vegetation management and easement surveys are significantly driven by both the length of the pipeline route and the nature of the environment through which the pipeline runs. The pipeline route of the GGT is one of the longest in the nation, resulting in an increased level of easement management and maintenance, compared to other, shorter pipelines.
- Some operating cost items such as internal inspections ("pigging") and cathodic protection are driven by the actual length of the pipe. In the case of the GGT, the relevant length for such costs is the entire 1378km of the pipeline.
- The GGP's remote location, requiring fly-in/fly-out and remote accommodation arrangements, additional personnel costs arising from relevant award conditions, complexity of contractual arrangements for pipeline services.

(b) Meaningful basis of benchmarks

Benchmarks must have a sound basis to be meaningful. In order to derive a meaningful set of benchmarks it is necessary to have both an understanding of the pipeline industry and its cost drivers.

While there are a number of broad factors that affect costs the primary cost driver is the length of the pipeline. Other secondary cost drivers are compressor stations and receipt and delivery stations.

Pipeline throughput and capacity do not have a significant impact on operating costs. Measures that use these are generally invalid.

The best indicators use either pipeline length or a replacement value, such as ORC. The non-capital cost benchmarks used in this Access Arrangement are:

- $ cost per km of pipeline length
- $ cost per mmkm of pipeline diameter x length

The costs benchmarked below reference the GGT forecast non-capital cost figure used in this Access Arrangement.

11.3 Comparator Pipelines

The following pipelines were used as comparators given the availability of regulatory decisions on the efficient non-capital costs of those pipelines.

- Gasnet / Vencorp
- Moomba-Adelaide Pipeline
- Dampier-Bunbury Natural Gas Pipeline
- Roma-Brisbane Pipeline
- Moomba Sydney Pipeline

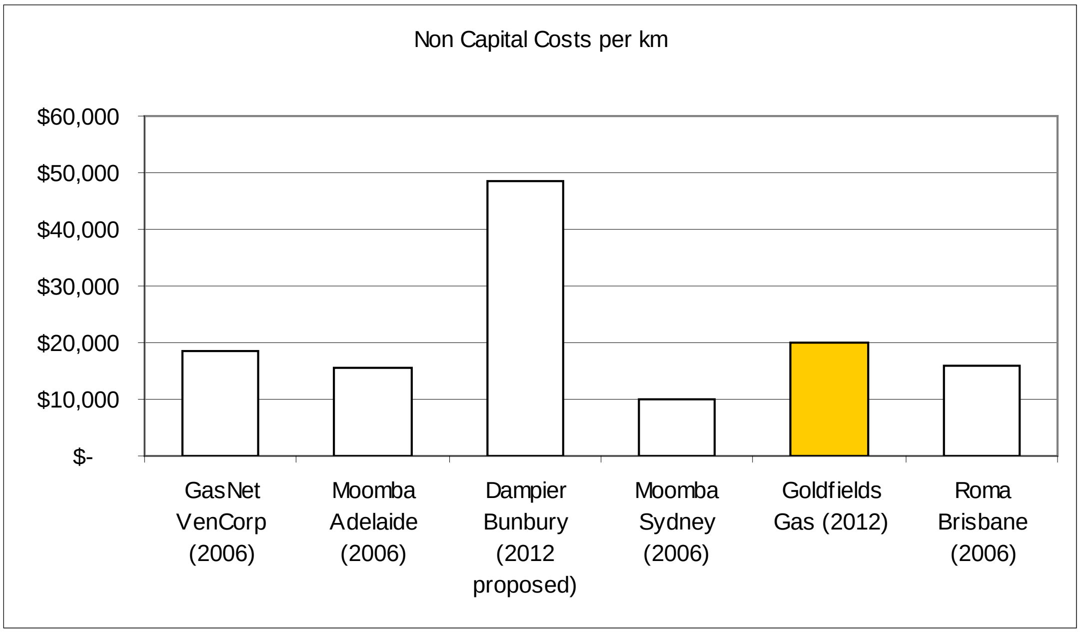
To allow meaningful comparisons the performance measures in this section of the Access Arrangement Information reflect non-capital costs as reflected in various regulatory decisions. These costs are not completely comparable due to differing treatments of inflation and corporate costs, and the different ages, locations and physical characteristics of the pipelines.

11.4 Key findings

Generally GGP's non-capital cost levels are in line with industry standard.

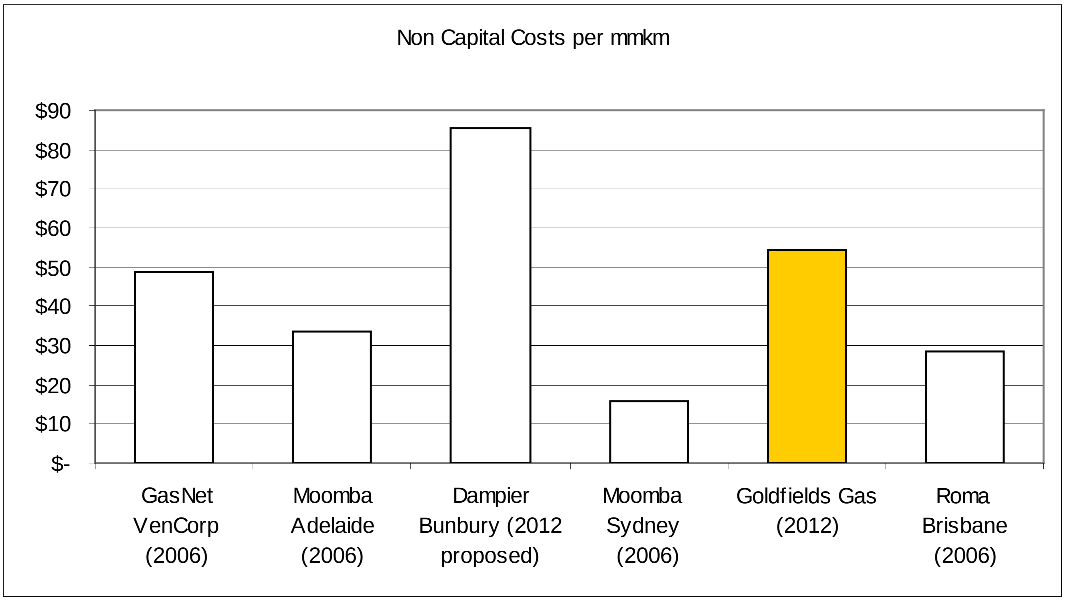
(a) Non-Capital cost per km

For non-capital cost per kilometre of pipeline route the GGP's performance is in line with relevant comparator pipelines.



(b) Non capital cost as a percentage of mmkm

Similarly, on the basis of comparing non-capital cost per kilometre of pipeline route multiplied by the size of the pipeline, the GGP performs moderately relative to other pipelines.



12 SYSTEM DESCRIPTION

The GGP extends from Yarraloola, in the Pilbara region of Western Australia, to Kalgoorlie, in the southern Goldfields region. The GGP transports gas from producers in the Carnarvon Basin to a variety of end users in the East Pilbara and Goldfields.

The Covered Pipeline system comprises:

- DN 400 mm and DN 350 mm main pipeline sections,
- the DN 200 mm lateral to Newman,
- 4 compressor stations on the pipeline, at Yarraloola, Paraburdoo, Ilgarari and Wiluna,
- custody inlet transfer meter stations at Yarraloola and various outlet custody transfer meter stations (see below),
- a head office in Perth,
- a gas control centre in Kewdale,
- maintenance bases and regional offices in Karratha, Newman, Leinster, and Kalgoorlie,
- a backup gas control centre in Perth,
- a Supervisory Control and Data Acquisition (SCADA) system,
- a satellite data communications system,
- a satellite telephone system,
- a field operations radio communications system, and
- operations, maintenance, commercial, quality, safety, and environmental management systems.

Gas is currently input to the Pipeline from the following two separate Inlet Points at Yarraloola:

- Harriet Joint Venture meter station near Compressor Station One on the Dampier to Bunbury Natural Gas Pipeline; and
- Compressor Station One on the Dampier to Bunbury Natural Gas Pipeline.

Gas is currently being delivered to the following Outlet Points for transportation of gas to end users at:

- Newman;
- Plutonic
- Wiluna
- Jundee;
- Mount Keith;
- Leinster;
- Leonora;
- Parkeston (via a third party lateral);
- Kalgoorlie North
- Kalgoorlie domestic distribution via a third party lateral;
- Kalgoorlie South; and
- Kambalda (via third party lateral from Kalgoorlie South).

Key system characteristics and parameters for the Covered Pipeline include:

Commissioned (Pipeline)	June to October 1996
Pipeline licence WA - PL 24	Expires 27 January 2016
Pipeline length	1378 kilometres
Pipeline diameter: Yarraloola to Newman	DN 400 mm (16 inch)
Pipeline diameter: Newman to Kalgoorlie	DN 350 mm (14 inch)
Maximum Allowed Operating Pressure	10.2 MPa
Pipe grade	X70
Corrosion mitigation	Trilaminate pipe coating; Impressed current cathodic protection
Installed compression	
Yarraloola	2 x 1290 kW Waukesha reciprocating, gas engine driven
Paraburdoo	1 x 1200 kW Solar Saturn gas turbine
Ilgarari	2 x 1290 kW Waukesha reciprocating, gas engine driven
Wiluna	1 x 1200 kW Solar Saturn gas turbine
Active Inlet Points	2
Active Outlet Points	12
Inactive Outlet Points	2
Main Line Valves	11
Scraper (pig) launch and/or receive facilities	11
Maintenance bases	4
Pipeline control	remote via SCADA
Right of Way identification	marker signs; at least one visible at any ROW location

Map of Covered Pipeline