GOLDFIELDS GAS PIPELINE

Access Arrangement Revision Proposal

Supporting Information

PUBLIC VERSION

15 August 2014

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Access arrangement revisions proposal

Goldfields Gas Transmission Joint Venturers Southern Cross Pipelines Australia Pty Ltd, Southern Cross Pipelines (NPL) Australia Pty Ltd and Alinta DEWAP Pty Ltd, and pipeline manager Goldfields Gas Transmission Pty Ltd (GGT), have prepared proposed revisions to the Access Arrangement for the Goldfields Gas Pipeline (GGP Access Arrangement). These revisions are the first prepared in accordance with the requirements of the National Gas law (NGL) and the National Gas Rules (NGR). They have been submitted to the Western Australian Economic Regulation Authority (ERA) for approval is accordance with the requirements of s. 132 of the NGL. The revisions have been submitted by GGT as the complying service provider for the service provider group.

GGT is required to submit to the ERA, and has submitted, an access arrangement revision proposal which:

(a) sets out the amendments to the GGP Access Arrangement proposed for the next access arrangement period; and

(b) incorporates the text of the access arrangement in the revised form.

The access arrangement revision proposal also includes the access arrangement information required by rule 43(1).

In addition, GGT has prepared the Supporting Information which follows. The Supporting Information explains why the Goldfields Gas Transmission Joint Venturers have made the amendments to the GGP Access Arrangement which are set out in the access arrangement revision proposal.

Some of the amendments give effect to specific requirements of the NGL and the NGR. Others are intended to align the GGP Access Arrangement and, in particular, its terms and conditions of reference service provision, with APA Group's national operations, and with access arrangements in effect elsewhere in Australia. The development of a set of terms and conditions which is applicable nationally facilitates contracting with those pipeline users which also have national businesses, and facilitates pipeline operation. The changes also have the effect of making the GGP Access Arrangement easier to read and use.

Demand for pipeline services

The demand for pipeline services provided using the Covered Pipeline is dependent on conditions in international commodity markets, principally the markets for gold and nickel. Some gas is transported for power generation in regional communities, and a small quantity is delivered into the Kalgoorlie distribution system for commercial and residential use in the town.

Gold prices have fallen, and there is significant uncertainty around the mining and processing of nickel ore. Long established users of the GGP are contemplating reduced contracted capacities.

The AngloGold Ashanti-Independence joint venture Tropicana mine is one of the few recent major gold mining developments in Australia. Gas for Tropicana, and for AngloGold's Sunrise dam project, is expected to be transported via the GGP from 2016.

Forecast capital expenditure

Forecast capital expenditure for the access arrangement period has been kept to a minimum. No provision has been made for expansion of pipeline services, and the forecast expenditure is largely for replacement of smaller items of plant and equipment on a pipeline which is now some 20 years old.

Forecast conforming capital expenditure: 2015-2019

2015	2016	2017	2018	2019
$ million	$ million	$ million	$ million	$ million
6.784	4.238	1.428	0.803	0.743

Forecast operating expenditure

The ability to access industry best practices of the broader APA Group has resulted in a dramatic containment of the costs of operating and maintaining the GGP. Significant efficiency improvements are reflected in the operating expenditure forecast for the access arrangement period.

Forecast operating expenditure: 2015-2019

2015	2016	2017	2018	2019
$ million	$ million	$ million	$ million	$ million
24.762	24.899	25.651	26.352	27.675

Total revenue and reference tariff

For the first time, the total revenue for the GGP has been determined after tax (as is now required by the NGR).

Total revenue: 2015-2019

	2015	2016	2017	2018	2019
	$ million	$ million	$ million	$ million	$ million
Return	38.247	37.903	37.278	36.364	35.381
Depreciation	10.349	10.716	10.906	10.991	11.003
Over-depreciation prior period	-3.211	0.000	0.000	0.000	0.000
Operating expenditure	25.277	25.413	26.168	26.897	28.263
Cost of tax	0.591	3.677	9.994	10.132	10.030
Value of imputation credits	-0.148	-0.919	-2.498	-2.533	-2.507
Total revenue	**71.105**	**76.790**	**81.848**	**81.851**	**82.170**

GGT has not changed the structure of the reference tariff, or the way in which tariff the total revenue has been allocated to the components of the tariff.

Proposed revised reference tariff

Toll charge	$/GJ MDQ	0.235806
Capacity reservation charge	$/GJ MDQ km	0.001459
Throughput charge	$/GJ km	0.000442

Importantly for users of the GGP, GGT's proposal delivers a revised reference tariff that increases by less than inflation. For example, the GGT proposal means for users in Kalgoorlie (assuming 100% capacity utilisation), a proposed revised reference tariff that is only 1.5% higher than the current tariff.

1 Introduction

In April 1993, a joint venture, the Goldfields Gas Transmission Joint Venture (GGT JV), was created to respond to a call, by the Government of Western Australia, for expressions of interest in the construction of a transmission pipeline to deliver gas into the Pilbara and Goldfields regions of the State.

Construction of the pipeline, the Goldfields Gas Pipeline (GGP), and its subsequent operation, were facilitated by an agreement between the GGT JV participants and the State of Western Australia (GGP State Agreement), which was ratified by the Goldfields Gas Pipeline Agreement Act 1994.

The original joint venture participants were Wesminco Oil Pty Ltd, Normandy Pipelines Pty Ltd and BHP Minerals Pty Ltd.

The current joint venture participants, and their shares in the GGT JV, are:

(a) Southern Cross Pipelines Australia Pty Ltd (62.664%);

(b) Southern Cross Pipelines (NPL) Australia Pty Ltd (25.493%); and

(c) Alinta DEWAP Pty Ltd (11.843%).

Southern Cross Pipelines Australia Pty Ltd and Southern Cross Pipelines (NPL) Australia Pty Ltd are APA Group entities. Alinta DEWAP Pty Ltd is an entity within the Alinta Energy group.

Under the GGP State Agreement, the GGT JV participants have access to the capacity of the GGP which they, and their associates, require for their own use. The joint venture participants are to provide third parties with access to such capacity, including developable capacity, as may from time to time not be contracted or utilised (GGP State Agreement, Clause 20(1)).

The parties to the GGP State Agreement contemplated uniform laws or subsidiary legislation being promulgated for gas pipeline operation in Western Australia. The terms and conditions of third party access to the GGP were to be subject to and in accordance with these uniform laws (GGP State Agreement, Clauses 20(2) and 21(2)).

Uniform laws were subsequently promulgated in the form of the Gas Pipelines Access (Western Australia) Act 1998 which implemented the access regulatory regime of the National Third Party Access Code for Natural Gas Pipeline Systems (Code) in Western Australia. The relevant regulator was the Western Australian Independent Gas Pipelines Access Regulator.

The GGP, as it was configured at the time the 1998 Act came into effect, was a covered pipeline; it was subject to the scheme of access regulation of the Code.

A covered pipeline subject to the scheme of access regulation of the Code was to have an access arrangement established to the satisfaction of the relevant regulator.

On 14 July 2005, the ERA made a Further Final Decision pursuant to section 2.19 of the Code to approve a revised proposed access arrangement which had been submitted by GGT. The Access Arrangement for the Goldfields Gas Pipeline (GGP Access Arrangement) had effect from 1 August 2005.

In 2006, the capacity of the Goldfields Gas Pipeline was increased by installing a second compressor at Paraburdoo. In 2009, compressors were installed at Wyloo West and Ned's Creek, further increasing the capacity of the pipeline. Elections were made, pursuant to the extensions and expansions policy of the GGP Access Arrangement, that the additional capacity provided by the compressors at Paraburdoo, at Wyloo West and at Ned's Creek would not be covered.

The covered pipeline was the pipeline, compressors and associated facilities providing that part of the capacity of the GGP which was covered. The GGP Access Arrangement was an access arrangement for the covered pipeline.

In January 2010, the National Gas Access (WA) Act 2009 came into effect, replacing the regime of access regulation of the Code with the regime of the National Gas Law (NGL) and the National Gas Rules (NGR). A transmission pipeline which was covered under the Code (an old scheme covered transmission pipeline) is deemed, by clause 6 of Schedule 3 to the NGL, to be a covered pipeline on commencement of the NGL. The Covered Pipeline is now a covered pipeline for the purposes of the regulatory regime for access to the services provided by pipelines set out in the NGL and the NGR.

The National Gas Access (WA) Act 2009 assigns the economic regulatory functions and powers of the NGL to the ERA.

1.1 Service provider and covered pipeline service provider

A service provider is a person who:

(a) owns, controls or operates; or

(b) intends to own, control or operate,

a pipeline or scheme pipeline, or any part of a pipeline or scheme pipeline (NGL, s. 8(1)).

The GGT JV participants assigned the tasks of developing and operating the GGP to a manager. Among other things, the manager is to develop the market for gas transmission services, and is responsible for preparing and maintaining tariff schedules and contract terms and conditions relating to the transportation of gas in the GGP.

Unless the joint venture participants agree otherwise, the manager is to be a company whose issued share capital is to be owned by one or more of the participants, or by related body corporates of one or more of the participants. The manager was initially, and continues to be, Goldfields Gas Transmission Pty Ltd (GGT). GGT is now a wholly owned subsidiary of APA Group.

GGT controls and operates the GGP. GGT is a service provider for the Covered Pipeline.

GGT is not the only service provider for the pipeline. The current joint venture participants, Southern Cross Pipelines Australia Pty Limited, Southern Cross Pipelines (NPL) Australia Pty Ltd and Alinta DEWAP Pty Ltd, own the GGP. They are also service providers for the GGP.

GGT, Southern Cross Pipelines Australia Pty Limited, Southern Cross Pipelines (NPL) Australia Pty Ltd, and Alinta DEWAP Pty Ltd comprise a service provider group in respect of the GGP.

Each of Southern Cross Pipelines Australia Pty Limited, Southern Cross Pipelines (NPL) Australia Pty Ltd and Alinta DEWAP Pty Ltd has given its written permission for GGT to act on behalf of the service provider group in respect of service provider requirements under the NGL and the NGR. GGT is, then, in accordance with s. 10(2) of the NGL, the complying service provider for the service provider group which owns or controls the GGP.

GGT has, as a covered pipeline service provider and as the complying service provider, submitted to the ERA, for approval under the NGR, proposed revisions to the GGP Access Arrangement in accordance with the requirement of s. 132 of NGL.

1.2 Revisions to the GGP Access Arrangement

Section 132 of NGL requires that a covered pipeline service provider submit, for approval by the ERA under the NGR, in the circumstances and within the time period specified by the NGR, revisions to a full access arrangement. Accordingly, GGT submitted to the ERA, on 15 August 2014, an access arrangement revision proposal for the GGP Access Arrangement (GGT's full access arrangement proposal) which, as required by rule 52 of the NGR:

(a) set out the amendments to the access arrangement that the service provider proposed for the next access arrangement period; and

(b) incorporated the text of the access arrangement in the revised form.[1]

GGT's full access arrangement proposal also included the access arrangement information (GGP Access Arrangement Information) required by rule 43(1) to assist users and prospective users of the GGP understand the background to the proposal.

The revisions to the GGP Access Arrangement provide for price regulation as required by the NGR, and address all other matters for which the NGR require that provision be made in an access arrangement. If the proposed revisions are approved by the ERA, then the revised GGP Access Arrangement will be full access arrangement for the purposes of the NGL and the NGR.

[1] Subsequent references to specific rules of the NGR will be designated rule [number]. All references will be to Version 20 of the NGR.

GGT has proposed changes to the form and content of the GGP Access Arrangement. Some of these changes give effect to specific requirements of the NGL and the NGR (requirements which were not in the Code, or which vary from those in the Code).

Other changes are intended to align the GGP Access Arrangement and, in particular, its terms and conditions of reference service provision, with APA Group's national operations, and with access arrangements in effect elsewhere in Australia. The development of a set of terms and conditions which is applicable nationally facilitates contracting with those pipeline users which also have national businesses, and facilitates pipeline operation.

These changes also have the effect of making the GGP Access Arrangement easier to read and use.

Information supporting GGT's full access arrangement proposal, and explanations for the changes made to the GGP Access Arrangement, are provided in this document, GGT's Supporting Information (Supporting Information).

1.3 Supporting Information

This Supporting Information provides additional information to assist the ERA in its process of approving GGT's full access arrangement proposal in accordance with the requirements of the NGL and the NGR.

The Supporting Information provides additional information on:

(a) the GGP Access Arrangement, including changes made to the access and queuing requirements (section 2);

(b) total revenue, cost allocation and reference tariff determination principles (section 3);

(c) the demand for pipeline services (section 4);

(d) depreciation (section 5);

(e) actual and projected capital expenditures, and roll forward of the capital base (section 6);

(f) rate of return (section 7);

(h) estimation of the cost of corporate income tax (section 8);

(i) operation of an incentive mechanism (section 9);

(j) forecast operating expenditure (section 10); and

(j) the proposed revised reference tariff and the reference tariff variation mechanism (section 11).

The following attachments are part of the Supporting Information:

Attachment 1:	Changes to the GGP Access Arrangement;
Attachment 2:	HoustonKemp Economists, *Methodology for Allocating Goldfields Gas Pipeline Costs*, June 2014;
Attachment 3:	Tom Hird, CEG (Competition Economists Group), *Cost Allocation for the Goldfields Gas Pipeline*, June 2014;
Attachment 4:	HoustonKemp Economists, *Depreciation Methodology for the Goldfields Gas Pipeline*, 12 August 2014;
Attachment 5:	Conforming capital expenditure: 2010-2014;
Attachment 6:	Forecast conforming capital expenditure: 2015-2019;
Attachment 7:	SFG Consulting, *Cost of equity for the Goldfields Gas Pipeline: Report for Goldfields Gas Transmission*, July 2014;
Attachment 8:	SFG, *Alternative versions of the dividend discount model and the implied cost of equity: Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid*, 15 May 2014;
Attachment 9:	Operating expenditure over earlier access arrangement period: auditor review reports;
Attachment 10:	Major expenditure jobs: 2015-2019; and
Attachment 11:	KPMG, *Corporate Cost Benchmarking: Goldfields Gas Pipeline*, June 2014.

2 GGP Access Arrangement

The proposed revisions to the GGP Access Arrangement are revisions to an applicable access arrangement that is a full access arrangement in respect of the pipeline services which the service provider provides or intends to provide in the circumstances specified by the NGR. In accordance with rule 48 of the NGR, a full access arrangement must:

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

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

(c) specify the reference services;

(d) specify for each reference service:

  (i) the reference tariff; and

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

(e) in the case of a transmission pipeline, set out the queuing requirements;

(f) set out the capacity trading requirements;

(g) set out the extension and expansion requirements;

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

(i) state the review submission date and the revision commencement date.

GGT's access arrangement proposal includes each of these matters specified in rule 48.

In this section of the Supporting Information, GGT:

(a) describes the services it intends to provide using the Covered Pipeline, and identifies the reference service specified in the GGP Access Arrangement;

(b) discusses proposed changes to the body of the GGP Access Arrangement, changes which give effect to requirements of the NGL and the NGR which were not requirements of the Code, and which align the GGP Access Arrangement with access arrangements for other pipelines operated by APA Group;

(c) sets out its reasons for the proposed change from access priority determined on a first come, first served basis for existing capacity to priority established on the basis of a publicly notified auction;

(d) sets out an 'open season' process for determining the priority for access to developable capacity; and

(d) outlines proposed changes to terms and conditions on which the reference service will be provided, and provides the reasons for those changes.

Information pertaining to the setting of the reference tariff for the reference service is provided in subsequent sections of the Supporting Information.

2.1 Pipeline services

2.1.1 Rules governing pipeline services

The scheme of access of the NGL and the NGR is a scheme of access to pipeline services. A pipeline service is defined (NGL, s. 2(1)) as:

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

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

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

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

A full access arrangement must describe the pipeline services the service provider proposes to offer to provide by means of the pipeline (rule 48(1)).

At least one of the pipeline services is to be specified as a reference service. A reference service is to be a pipeline service that is likely to be sought by a significant part of the market (rule 101).

2.1.2 Pipeline services provided using the Covered Pipeline

GGT provides, using the Covered Pipeline, the following gas transportation services:

(a) firm transportation service; and

(b) negotiated service.

A firm transportation service is a service whereby the pipeline operator receives from a user, at the receipt point, on a day, a quantity of gas not exceeding the maximum daily quantity specified in the user's gas transportation agreement (MDQ), and delivers to the user, at one or more delivery points, on that day, a quantity of gas not exceeding the user's MDQ, without interruption or curtailment, except in the specific and limited circumstances set out in the user's gas transportation agreement.

A negotiated service is a gas transportation service to meet specific needs of a user, needs which differ from those of a user of the firm transportation service. Examples of negotiated services include as-available and interruptible services.

When pipeline capacity is limited, firm transportation service has priority over interruptible service for the delivery of gas.

2.1.3 Reference service

The GGP Access Arrangement describes a single reference service: Firm Service. The Firm Service remains appropriate as the reference service for the next access arrangement period.

Paragraph 84 of the ERA's October 2009 Draft Decision on proposed revisions to the GGP Access Arrangement advised that the ERA had ascertained, from material submitted by GGT and users, and from its own knowledge of the market, that the Firm Service was a firm transportation service which was likely to be sought by a significant part of the market.

There has been no material change in the market for gas transportation services, as assessed by the ERA in 2009, and the Firm Service continues to be the appropriate and relevant reference service. GGT does not consider that any other service is likely to be sought by a significant part of the market. Current gas transportation agreements for the GGP are overwhelmingly for firm service.

The Firm Service of the GGP Access Arrangement has, therefore, been retained by GGT as the single reference service for the purposes of the access regime of the NGL and the NGR.

GGT has revised the minimum term of a transportation agreement for Firm Service to five years. This is consistent with the majority of contracts on the GGP, which have terms of five years or longer. Users of the GGP make complementary investments in assets – principally for electricity generation and mineral processing – which are difficult to redeploy from their Pilbara and Goldfields locations. Those users generally seek to recover their investments in these assets over the next period of relatively high commodity prices. Shorter term contracts are potentially available as negotiated services.

2.1.4 Non-reference services

A negotiated service is a service provided using the Covered Pipeline which is not the Firm Service. GGT offered to provide negotiated services as non-reference services under the scheme of the Code. GGT is proposing to continue to offer negotiated services under the scheme of the NGL and the NGR.

The terms and conditions on which negotiated services are provided are negotiated individually with prospective users to meet those users' specific requirements. A negotiated service cannot therefore be considered to be sought by a significant part of the market, and should not be classified as a reference service.

Negotiated services include as-available and interruptible services. In GGT's experience during earlier access arrangement periods, prospective users inquire, in the first instance, about the availability of firm service. Prospective users seek firm

service in preference to these "non-firm" services. GGT expects that this will continue to be the case during the access arrangement period.

2.1.5 Gas specification

There is continuing uncertainty around the quality of gas which may be delivered into the GGP. Although the GGP and, in consequence, the Covered Pipeline, is a PIA pipeline for the purposes of the Gas Supply (Gas Quality Specifications) Act 2009, no reference specification has been set for the pipeline.

The original joint venture participants initially constructed the GGP with a capacity based on the assumption that the Gross Heating Value (GHV) of gas delivered into the pipeline would exceed 39.0 MJ/m^3. Virtually all gas transportation agreements with users of the Covered Pipeline require that gas delivered into the pipeline have a GHV exceeding 37.0 MJ/m^3.

The ERA's October 2009 Draft Decision assumed (no evidence was provided) that a minimum GHV above 35.5 MJ/m^3 would adversely affect competition because BHP Billiton Nickel West may be unable to supply shippers on the GGP to whom it currently delivers gas. Gas supplied to BHP Billiton Nickel West is currently delivered into the GGP from the Dampier to Bunbury Pipeline. The reference specification for the Dampier to Bunbury Natural Gas Pipeline includes a minimum GHV of 37.0 MJ/m^3, and this has become the de facto market standard. If gas specification affects competition, and there is no evidence that it does, the DBNGP reference specification is the relevant determining factor.

GGT has proposed that the minimum GHV of the gas specification of the GGP Access Arrangement, consistent with that of the Dampier to Bunbury Natural Gas Pipeline, be reset to 37.0 MJ/m^3. A new clause 2.2.3 then operates to remove ambiguity for users, and for GGT, by providing for:

(a) the downward adjustment of user capacity entitlements in the event of gas delivered into the pipeline having an average GHV less than 37.0 MJ/m^3, ensuring all users can, proportionately, avail themselves of their capacity entitlements; and

(b) the upward adjustment of the components of the reference tariff, ensuring GGT has the opportunity to recover its efficiently incurred costs of providing the reference service

GGT notes that the AER adopted a similar provision in the Access Arrangement for the Roma to Brisbane Pipeline when drafting and approving its own revised access arrangement for the pipeline in 2012.

2.2 Changes to the GGP Access Arrangement

GGT has revised the GGP Access Arrangement to apply during the next access arrangement period. Key revisions:

(a) modify the access arrangement (which was prepared, and last revised, under the access regime of the Code) so that it is consistent with the regime of the NGL and the NGR; and

(b) align the GGP Access Arrangement with other approved APA Group access arrangements, and align the access arrangement terms and conditions with the terms and conditions which have been incorporated into recent gas transportation agreements.

2.2.1 Changes for consistency with the NGL and the NGR

The GGP Access Arrangement has been revised to be consistent with the requirements of the NGL and the NGR. The changes made are largely associated with the adoption of new terms used in the NGL and the NGR. Some further revisions are required to comply with new requirements, for example in relation to capacity trading.

2.2.2 Alignment with other access arrangements and with current contracting practice

GGT has modified the GGP Access Arrangement to align with the current form and structure of APA Group access arrangements. Some of the items that were previously included in the general terms and conditions have been transferred into the main body of the access arrangement. In particular, the description of the Firm Service reference service has been transferred into Chapter 2 of the GGP Access Arrangement, and all tariff and charging elements have been transferred into Chapter 4 and Schedule 1.

The following parts of the GGP Access Arrangement have been substantially revised so that they align (where possible) with other gas transportation agreements in place for GGT and APA Group:

(a) Pipeline services (Chapter 2) – overview of the key elements of the Firm Service, and of negotiated services;

(b) Reference tariffs and other charges (Chapter 4) – details of tariffs and charges applicable to the Firm Service;

(c) Definitions and interpretation (Schedule C) – incorporating definitions arising from revised access arrangement and terms and conditions applying to the firm service; and

(d) Terms and conditions for the Firm Service (Schedule D) – details of the terms and conditions on which the Firm Service will be provided.

GGT notes that the proposed changes to the terms and conditions for the Firm Service are changes which have previously been approved by the Australian Energy Regulator as being in accordance with the NGL and NGR in respect of reference services for the Amadeus Gas Pipeline and the Roma Brisbane Pipeline. Minor variations from the terms and conditions approved for these pipelines are limited to those required to accommodate the specific circumstances of the GGP and, in

particular, to recognise the single location of the two receipt points on the GGP, and the regulatory regime in respect of gas quality in effect in Western Australia.

Attachment 1 to the Supporting Information provides a detailed list of the proposed revisions to GGP Access Arrangement and associated terms and conditions, and notes the reasons for the changes.

GGT considers that its proposed revisions to the GGP Access Arrangement are necessary and appropriate, and that they are consistent with the national gas objective (NGL, s. 23). They either reflect changing regulatory requirements, or bring the access arrangement into alignment with other APA Group access arrangements and with current contracting practice within APA Group and on the GGP. The benefits of this alignment are discussed further in the following section.

2.2.3 Access arrangement terms and conditions for firm service

GGT has undertaken a comprehensive revision of the terms and conditions applying to provision of the Firm Service of the GGP Access Arrangement.

Since the terms and conditions of gas transportation were first developed for the GGP Access Arrangement (over a decade earlier), GGT contracting has evolved, both in response to negotiations with prospective users of the pipeline and, more recently, under the influence of APA Group, which operates a national gas transportation business. The terms and conditions which are currently in the GGP Access Arrangement no longer correspond with those negotiated with users in GGT and APA Group gas transportation agreements, or with the terms and conditions in the access arrangements for other APA Group pipelines.

Efficiency benefits are potentially available to both GGT and prospective users of the Covered Pipeline from having terms and conditions which are consistent across gas transportation agreements. These benefits are largely in the form of:

(a) better service provider and user understanding of the contractual arrangements for pipeline service provision;

(b) lower costs of the legal drafting of gas transportation agreements, and for legal advice obtained in respect of those agreements; and

(c) facilitation of pipeline capacity trading as a result of consistency across gas transportation agreements.

Furthermore, some pipeline users have national businesses, contract for service on multiple APA Group pipelines in different States and Territories, and benefit from consistency in contracting arrangements across those pipelines (where that consistency is possible and appropriate given the specific circumstances each the pipeline). The benefits are, again, the lower legal costs of contracting for pipeline services, and the lower administrative and legal costs of ongoing contract administration.

The terms and conditions on which the Firm Service reference service is to be provided using the Covered Pipeline have been modified substantially to align with those approved by the AER for the Roma to Brisbane Pipeline (RBP) Access Arrangement. The RBP terms and conditions are, largely, APA Group's standard terms and conditions. They are the terms and conditions which APA Group seeks to incorporate into the gas transportation agreements which it negotiates with prospective user of its pipeline systems across Australia. Through incorporation of these terms and conditions into the GGP Access Arrangement, APA Group is seeking to achieve, to the extent feasible given the differences between individual pipeline systems, national consistency across pipeline operations.

The terms and conditions of the GGP Access Arrangement will, of course, retain those clauses which are specific and necessary for operation of the GGP.

If the terms and conditions of reference service provision are revised in the way proposed, this will have the appearance of effecting significant change to the GGP Access Arrangement. However, the majority of changes are for one or more of the following three reasons:

(a) the change simplifies and/or streamlines the provisions of the GGP Access Arrangement in a way which has already been achieved (and approved by the AER) with the terms and conditions of the RBP Access Arrangement, but without changing the essence of those provisions;

(b) the change transfers material from the terms and conditions to the main body of the GGP Access Arrangement, so that the access arrangement more clearly complies with the requirements of rule 48; for example, the specification of the reference service and the specification of the reference tariff are, more appropriately, parts of the GGP Access Arrangement itself, rather than parts of the terms and conditions of the access arrangement; and

(c) the change removes parts of the terms and conditions which are obsolete either because they are not used in GGT's gas transportation agreements or they no longer accord with the way in which the GGP is operated; for example, the provisions for supplementary quantity options and for variation notices have been removed in their entirety, because they have never been used in gas transportation agreements.

GGT notes the following material changes proposed to the terms and conditions on which the Firm Service reference service is provided using the Covered Pipeline:

(a) Dispute resolution

The dispute resolution clause in the GGP Access Arrangement calls for reference of a matter in dispute to senior representatives of the parties, and then to an expert or arbitrator. The proposed terms and conditions envisage reference to senior representatives only. If the dispute is subsequently unresolved, then either party may commence litigation, or the parties can choose the path they consider most appropriate to resolving their dispute. This provides simplicity and flexibility in the dispute resolution process, and is

consistent with the practice in current gas transportation agreements (although the change is not currently incorporated in the terms and conditions of the RBP Access Arrangement).

(b) Liabilities and indemnities

GGT has proposed replacing the liability and indemnities regime of the GGP terms and conditions (clause 18) with the liability and indemnities regime of the terms and conditions in the RBP Access Arrangement. GGT considers that the revised liability and indemnity provisions reflect a more appropriate allocation of risk between the service provider and the user.

(c) Nominations

Changes to the clauses of the GGP terms and conditions which relate to nominations and forecasts will align GGP operation with the way in which APA Group operates its pipelines across Australia. The changes are, in general, relatively minor. The most significant of the changes is the reduction in the length of the notice period for nominations prior to the start of each month from at least 7 days to 3 days.

(d) Scheduling

There are no gas scheduling provisions in the terms and conditions of the GGP Access Arrangement. This can lead to ambiguity in respect of daily operation of the pipeline, and the scheduling provisions of the RBP Access Arrangement have been adopted to fill this gap.

(e) Connection

A number of the clauses in the terms and conditions of the GGP Access Arrangement, which relate to pipeline interconnection, have been removed. These clauses are not part of the terms and conditions on which the Firm Service reference service is to be provided. Pipeline interconnection is dealt with, separately, in the main body of the access arrangement. The specific terms and conditions of interconnection, which vary greatly depending on the circumstances of the pipelines which are to be interconnected, are left to the negotiation of connection agreements (as is usually the case).

The changes GGT has proposed also include changes to the terminology used in the GGP Access Arrangement. References to inlet points and outlet points have been changed to references to receipt points and delivery points, consistent with the use of the latter terms in the NGR. The term “service agreement”, which is not used in the NGL or the NGR, is to be replaced by “transportation agreement”. Although NGL and the NGR use the concept of pipeline service, contracts for pipeline services are commonly referred to as gas transportation agreements. These changes are reflected in the terms and conditions themselves, and also in the amended glossary/definitions section of the GGP Access Arrangement.

2.3 Review submission and revision commencement dates

In accordance with the requirement of rule 49 for a full access arrangement, GGT has proposed the following review submission and revision commencement dates:

(a) review submission: on or before 1 January 2019, or 4 years from the date of commencement of the (proposed) revisions to the GGP Access Arrangement; and

(b) revision commencement: the later of 1 January 2020 and the date on which the ERA approves the revisions to the GGP Access Arrangement to take effect under the NGL and the NGR.

The proposed review submission and revision commencement dates are consistent with the 'general rule' set out in rule 50. The ERA does not have discretion under the NGR not to approve proposals in respect of review submission and revision commencement dates that are consistent with the 'general rule'.

2.4 Trigger event

Clause 3.4 of the GGP Access Arrangement provides for acceleration of the review submission date on the occurrence of a trigger event. The circumstances which would have triggered access arrangement revision in accordance with clause 3.4 have now passed, and GGT has not included a new trigger event in its proposed revisions to the access arrangement.

The triggering of revisions to an access arrangement by pipeline expansion is, in GGT's view, inconsistent with the scheme of incentive regulation in the NGL and the NGR. It is inconsistent with the provision of effective incentives to promote efficient investment in a pipeline (NGL, s. 24(3)), and it is inconsistent with the requirement of the national gas objective for the promotion of efficient investment in natural gas services for the long term interest of consumers of natural gas (NGL, s. 23).

2.5 Extensions and expansions

GGT has proposed revisions of the extensions and expansions policy in the GGP Access Arrangement to align it with requirements and terminology of rule 104.

In proposing these revisions, GGT is not seeking to change the intent of the extensions and expansions policy, which was the subject of a decision by the Western Australian Electricity Review Board (ERB) in 2012.[2]

[2] Applications Nos. 1 and 2 of 2010, Supplementary Decision, 30 March 2012.

2.6 Access and queuing requirements

2.6.1 Rules governing access and queuing

Rule 103 requires that an access arrangement for a transmission pipeline contain queuing requirements, the purpose of which is to create a process or mechanism (or both) for establishing an order of priority between prospective users for spare or developable capacity in which all prospective users are treated on a fair and equal basis. In addition, rule 112 sets out requirements in respect of requests for access.

Rule 103 is a substantial revision from the corresponding section in the Code (section 3.12). In particular, rule 103 indicates that the queuing process or mechanism for spare capacity may be different from that for developable capacity, and states that queuing requirements might (for example) provide for an order of priority determined on a first come first served basis, or on the basis of a publicly notified auction in which all prospective users are able to participate.

Furthermore, queuing requirements are to be sufficiently detailed to enable a prospective user to understand the basis on which the order of priority is determined and, if a queue has been established, to determine the prospective user's position in the queue (rule 103(5)).

Rule 112 does not correspond with any provision that was in the Code, and therefore imposes new requirements to be addressed in the revised GGP Access Arrangement. Rule 112 clearly establishes a prospective user's right to request access, and sets out the process in accordance with which the service provider is to respond to the access request.

GGT has proposed revisions to the queuing requirements in the GGP Access Arrangement so that it complies with rule 112. Also, a scheme is introduced in which the order of priority of prospective users is established on the basis of a publicly notified auction for existing capacity, and through an open season for developable capacity. This scheme replaces the existing first come first served queuing policy, and the complex process through which a user applies for access, with a scheme which provides more efficient allocations of existing and developable capacity. Details of the queuing requirement of the proposed revised Access Arrangement are set out below.

2.6.2 Issues with a first come, first served queuing policy

Prospective users of the GGP have found application for existing or developable capacity, following the process set out in the GGT Information Package, complex and subject to uncertainty.

Furthermore, the existing first come first served queuing policy of clause 7 of the GGP Access Arrangement takes no account of GGT's costs of service provision, and of prospective user valuation of the service. In these respects, the existing policy does not offer a fair allocation of capacity to prospective users, or a process that leads to the efficient allocation of spare or developable capacity. There is, then, no reason to expect that a first come, first served queuing policy will promote efficient investment in,

and efficient operation and use of, natural gas services for the long term interests of consumers.

In addition, a number of practical problems arise under a first come, first served policy.

We illustrate with two examples.

Example 1

Prospective User 1 (PU 1) applies for 5 TJ/d of existing capacity for the period 2019 to 2024. Prospective User 2 (PU 2) applies for 15 TJ/d of existing capacity for the period 2019 to 2029. Both applications are for the reference service at the reference tariff, both are correctly completed, GGT provides spare capacity responses, and PU 1 and PU 2 submit completed order forms. PU 1's order form is submitted before the order form from PU 2.

15 TJ/d of firm capacity becomes spare.

Under a first come, first served queuing policy, PU 1 has priority and is allocated 5 TJ/d. PU 2 has a project which requires 15 TJ/d if it is to proceed, and is not willing to accept 10 TJ/d.

The outcome is an inefficient use of pipeline capacity. If no other prospective user applies, there will be uncontracted capacity of 10 TJ/d from 2019. Furthermore, there may be uncontracted capacity once PU 1's transportation agreement terminates in 2024.

If the net economic benefit of PU 2's project is expected to exceed the net benefit from capacity allocation to PU 1, the outcome is not in the interests of users and consumers of natural gas.

Example 2

PU 1 applies for 10 TJ/d of firm service reference service, at the reference tariff, for the period 2022 to 2025. PU 2 requires for a project, and applies for, negotiated service using 10 TJ/d, at a negotiated tariff, for the period 2019 to 2029. PU 1 has priority over PU 2, and spare capacity of 10 TJ/d is available from 2019.

Under a first come, first served queuing policy, PU 1 is allocated 10 TJ/d in 2022. PU 2 has a project which requires 10 TJ/d, and the project cannot proceed.

The outcome is an inefficient use of pipeline capacity. Capacity is unused between 2019 and 2022. Furthermore, if the net economic benefit of PU 2's project is expected to exceed the net benefit from capacity allocation to PU 1, the outcome is not in the interests of users and consumers of natural gas.

From the perspective of a prospective user, securing pipeline capacity is usually only one of a number of activities which must be completed as part of project implementation (which might be development of a gas fired power station, or

development of such a power station as part of a larger mining and minerals processing project). Where securing pipeline capacity is part of a larger project, the project proponent will usually seek to join the queue for capacity at an early date but will avoid committing to capacity until capacity is "on the critical path" for its project. A prospective user may be at the front of the queue, but not ready to contract for capacity. Another prospective user may be further back in the queue and, because the other parts of its project have progressed quickly, may be ready to contract for capacity but cannot be accommodated until arrangements have been concluded with the prospective user at the front of the queue. That user will usually be reluctant to lose its priority by formally withdrawing its application for capacity, and the operation of a first come, first served queuing policy can become administratively difficult and imposes costs on those prospective users who must wait.

This problem is exacerbated when there is no cost to a prospective user joining the queue, and where prospective users at the front of the queue want to take capacity later and/or for shorter periods than those further down in the queue.

A first come, first served queuing policy does not allow the flexibility for higher value projects to take precedence over lower value projects when it is not possible to meet the needs of both.

If capacity must be developed, the coordination of queuing and capacity allocation becomes difficult due, in part, to the sequential nature of the process under a first come, first served policy. Expansion to meet the timing requirements of individual prospective users becomes difficult to achieve.

2.6.3 Proposed queuing requirements – existing capacity

Given these issues with a first come, first served queuing policy, GGT has proposed incorporating into the GGP Access Arrangement queuing requirements for existing capacity in the form of a publicly notified auction in which all prospective users of spare capacity can participate.

The key features of the proposed requirements are:

(a) GGT will accept expressions of interest in existing capacity; these expressions of interest will not be associated with any ranking or priority of access to capacity;

(b) GGT will confirm with each prospective user that it has received that user's expression in interest, inform the prospective user of any available spare capacity and of whether investigations are required to confirm spare capacity, and provide details of other registrations for capacity received from other prospective users (without disclosing prospective user confidential information);

(c) GGT will notify all users and prospective users who have filed expressions of interest, and may advise other potentially interested parties, that an auction of existing capacity is planned;

(d) GGT will advertise the auction in local and national newspapers;

(e) all prospective users (those who have filed expressions of interest, and those responding to GGT's advertising) will be asked to submit bids which specify demand, volumes, commencement and end dates, and receipt and delivery points;

(f) bids may be for the reference service at the reference tariff, or for negotiated service for which the user proposes a negotiated tariff;

(g) prospective users will also be required to meet prudential requirements;

(h) bids are to be irrevocable, and submitted in the form of an executable contract;

(i) Prospective users may consult with GGT on the acceptability of potential alternative terms and conditions prior to submitting a bid;

(j) once the period allowed for the auction has expired, GGT will rank the bids on a net present value (NPV) basis, with bids which have a higher NPV ranked ahead of bids with a lower NPV; and

(k) the available existing capacity will be allocated to prospective users in turn, based on the NPV ranking, until all of the existing capacity is allocated.

A queuing requirement of this form represents a mechanism (that is, an auction) and a process which will determine the priority between competing requests for existing capacity at the time at which the auction is conducted.

The auction is a multi-stage (non-binding bids, followed by binding bids), first-price sealed bid auction for a complex service (capacity, location of delivery point, duration, tariff) with multiple winners.

GGT considers that the adoption of a public auction of this form will better meet the national gas objective than a first come, first served queuing policy.

An auction should promote the efficient use of natural gas services by ensuring that existing capacity is allocated to those users who value it most, and should, therefore, allocate capacity in a way that is in the long term interests of consumers with respect to price, reliability and security of supply. A first come, first served queuing policy does not allocate capacity according to user valuation and there is no reason to expect that it will promote the efficient use of capacity.

However, to be effective in achieving the efficient use of capacity, the form of the auction should preclude collusion among prospective users, encourage competition among them, and provide prospective users with as much information as is possible about the service being auctioned.[3]

The initial stages of the mechanism and process – submission of non-binding expressions of interest, and notification of all users and prospective users who have

[3] Paul Klemperer (2002), "What Really matters in Auction Design", Journal of Economic Perspectives, 16(1): pages 169-189.

filed expressions of interest, and other interested parties, that an auction of capacity is planned – are important for the provision of information to bidders and potential bidders.

Advertising the auction widely, and use of a sealed-bid format, should encourage competition in bidding, and the sealed-bid format should also limit opportunities for collusion among prospective users.

Requiring that prospective users meet prudential requirements is a practical efficiency measure. If the winning bidder were not financially viable, the auction would have to be held again, and the costs would be the cost of the second auction plus the costs of delay subsequently faced by all prospective users.

The submission of bids for the reference service at the reference tariff ensures that prospective users are protected from being required to pay more than the reference tariff for service. Moreover, for negotiated services the tariff paid for the capacity will be determined by the auction, and will not be set by GGT. A tariff will not be imposed on a prospective user by a pipeline service provider who might be perceived as being able to exercise market power.

2.6.4 Proposed queuing requirements – developable capacity

An 'open season' approach is proposed for developable capacity.

GGT considers that an open season approach is best suited for the allocation of developable capacity as efficient investment in pipeline capacity is facilitated by a process that aggregates similar capacity requirements into an efficient project. This is because the significant economies of scale for pipeline expansions mean that the per TJ cost of an expansion is likely to vary with the size of the expansion. An auction process (with a requirement to submit an executable contract with proposed tariffs) could not readily take account of this factor, and may undermine the success of any auction. As described above in section 2.6.2, a first come first serve queue also does not facilitate the efficient allocation of developable capacity.

As an alternative, GGT proposes an open season approach to the allocation of developable capacity whereby GGT will conduct a public process to aggregate all possible interest in developable capacity, and then, if there is sufficient demand for similar projects, commence negotiations with interested parties with the aim to develop the most efficient investment in additional capacity. The conclusion of negotiations will determine the order of priority for prospective users to developable capacity, and may result in more than one user gaining access to developable capacity at the same time.

GGT considers that this change in the queuing approach will better facilitate coordination between requests for developable capacity, and the identification of expansions which are optimally sized to meet the requests of more than one prospective user.

The key features of the proposed queuing requirements for developable capacity are:

(a) GGT will accept registrations of interest for developable capacity at any time; a registration of interest will not imply any priority of access to developable capacity;

(b) where registrations of interest or other factors indicate there is sufficient demand for developable capacity, GGT will, where the circumstances allow, advertise in local and national newspapers the potential for expansion of the pipeline in order to ensure that all potential users of an expansion have been identified;

(c) following receipt of the expressions of interest, GGT will undertake investigations where there appears to be sufficient interest in similar types of services which can potentially be met with similar types of investment (these investigations will focus on similar projects in order to achieve economies of scale); and

(d) once the investigations are completed, and assuming that GGT has identified a capacity development project for which there is sufficient interest, the developable capacity will be offered to prospective users by direct negotiations with those prospective users.

This mechanism and process (open season followed by negotiation) will determine the way in which users gain access to developable capacity.

The allocation of developable capacity on the basis of a public notification for expressions of interest, followed by a negotiation process which has been outlined above is likely to result in a more timely and effective means of coordinating capacity expansions than a first come, first served approach. This is because it provides for concurrent negotiations between parties for an expansion project that has the potential to satisfy the needs of multiple parties. The approach is therefore likely to facilitate more timely decisions on investment, and to facilitate expansions being optimally-sized in order to realise economies of scale.

As a result the proposed open season approach better meets the national gas objective. In particular the process should result in more efficient investment in natural gas services and should therefore be in the long term interests of consumers in relation to the price charged for the service, and in relation to reliability and security of gas supply.

2.6.5 Regulatory oversight of queuing process

GGT proposes to include regulatory oversight provisions in the GGP Access Arrangement for the ERA to be able to confirm that the queuing and open season processes are run in accordance with the queuing provisions in the Access Arrangement, and lead to timely outcomes.

Section 5.4.1 of the GGP Access Arrangement requires GGT to provide the ERA with a report from an independent auditor confirming that it has run the auction process for spare capacity in accordance with the Access Arrangement. Section 5.4.2 of the GGP Access Arrangement requires GGT to provide the ERA with a report on the progress

of negotiations pursuant to section 5.3.2, including whether GGT has entered into negotiations and the stage of those negotiations. This allows the ERA to monitor the time taken to conclude negotiations and to form a view as to the efficiency of the queuing process.

3 Total revenue, cost allocation and reference tariff determination: principles

The tariff for a reference service provided using a transmission pipeline is to be designed in such a way that the revenue earned from the provision of that service is to be the portion of the total revenue referable to that service (rule 95(1)).

This section of the Supporting Information describes the way in which GGT has determined the total revenue for the GGP, and has determined a proposed revised reference tariff from that total revenue.

The determination of the total revenue, and of the proposed revised reference tariff from that total revenue, are carried out in the tariff model which is Attachment 9 to the Supporting Information, and are reported in section 11 below.

3.1 Rules governing total revenue, cost allocation and reference tariff determination

The total revenue is to be determined for each regulatory year of an access arrangement period using the building block approach (rule 76). The building blocks of this approach are:

(a) a return on the projected capital base;

(b) depreciation of the projected capital base;

(c) the estimated cost of corporate income tax;

(d) increments or decrements resulting from the operation of an incentive mechanism to encourage gains in efficiency; and

(e) a forecast of operating expenditure.

The allocation of the total revenue to reference services and other services for the purpose of reference tariff determination and, ultimately, for cost recovery, is governed by rules 93 and 95 of the NGR.

The total revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services (rule 93(1)).

Costs are to be allocated between reference and other services as follows:

(a) costs directly attributable to reference services are to be allocated to those services (rule 93(2)(a));

(b) costs directly attributable to pipeline services which are not reference services are to be allocated to those services (rule 93(2)(b)); and

(c) other costs are to be allocated between reference and other services on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the regulator (rule 93(2)(c)).

That portion of the total revenue which is allocated to the provision of reference services is to be allocated between each of the reference services which the service provider proposes to provide by:

(a) allocating directly attributable costs to the provision of each service (rule 95(2)(a)); and

(b) allocating other costs attributable to the provision of reference services between them on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the regulator (rule 95(2)(b)).

That portion of the total revenue which is allocated to the provision of a particular reference service is to be allocated to a particular user or class of users by:

(a) allocating costs directly attributable to supplying the user or class of users to the relevant user or class (rule 95(3)(a)); and

(b) allocating other costs between the users or class of users and other users or classes of users on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the regulator (rule 95(3)(b)).

3.2 Determining the total revenue for the GGP

When the GGP Access Arrangement was last revised, total revenue for the purposes of determining reference tariffs was calculated as the total cost of providing pipeline services using the Covered Pipeline. Thus, total revenue included all costs associated with the provision of services using the Covered Pipeline, and excluded incremental capital and operating costs associated with uncovered assets.

This approach to calculating total revenue was approved by the ERA, as it was found to be consistent with the relevant provisions of the Code.[4] The decision of the ERA to approve this approach was upheld by the ERB on review. In Applications Nos 1 and 2 of 2010, the ERB found that the costs of providing services using the uncovered capacity of the GGP were to be excluded from the total revenue calculated under section 8.38 of the Code.[5] The total revenue was not to include the costs of providing services using that part of the pipeline system which was uncovered.

To comply with the directions of the ERB when determining the current reference tariff of the GGP Access Arrangement:

[4] Economic Regulation Authority, *Final Decision on GGT's Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 13 May 2010, paragraph 63.

[5] Western Australian Electricity Board of Review, Applications Nos 1 and 2 of 2010, Reasons for Decision, paragraph 200.

(a) the capital costs of those parts of the pipeline system (a second compressor added at Paraburdoo, in 2006, and compressors installed at Wyloo West and at Ned's Creek in 2009) which were uncovered were not included in the capital base; and

(b) the costs of operating and maintaining the uncovered parts of the pipeline system (the costs of operating and maintaining the compressors at Paraburdoo, Wyloo West and Ned's Creek, and a proportion of common operating costs attributed to those compressors) were excluded from the non-capital costs.

The NGL and the NGR include a scheme for the determination of total revenue which is similar to the scheme which was in place under the Code.

The scheme of the NGL and the NGR maintains the distinction between the covered and the uncovered parts of a pipeline system which was made in the Code, and the economic regulatory regime of the NGR applies only to the covered pipeline:

(a) section 132 of the NGL imposes the obligation to submit a full access arrangement proposal on a covered pipeline service provider;

(b) a covered pipeline service provider is a service provider that provides or intends to provide services by means of a covered pipeline (NGL, section 2, definition of "covered pipeline service provider"); and

(c) the covered pipeline service provider's obligation to submit a full access arrangement proposal is in respect of the services which that service provider provides or intends to provide in the circumstances specified by the rules (NGL, section 132).

The circumstances specified in the rules include:

(a) an access arrangement is required only for a covered pipeline (rule 46), a requirement reinforced by rule 53 which states that the regulator may direct the service provider to submit separate access arrangement proposals for different parts of the covered pipeline;

(b) a full access arrangement proposal is to identify the pipeline to which the access arrangement relates (rule 48(1)(a)); since the access arrangement relates to the covered pipeline, it is the covered pipeline which must be identified for the purposes of the proposal; and

(c) the full access arrangement proposal must describe the pipeline services which the service provider proposes to offer by means of the pipeline (rule 48(1)(b)); these services are the services provided using the covered pipeline.

More specifically, the price and revenue regulation of Part 9 of the NGR apply only in respect of a full access arrangement proposal (rule 70). They therefore apply only in respect of a covered pipeline.

In addition to, and consistent with, these circumstances specified by the rules, the regulator's economic regulatory functions and powers, including the functions and powers that relate to a full access arrangement decision, are functions and powers performed or exercised under the NGL and the NGR that relate to the regulation of pipeline services provided by means of, or in connection, with a covered pipeline (NGL, s. 2. definition of "AER economic regulatory function or power").

In the scheme of the NGL and the NGR, it is the covered pipeline which is subject to economic regulation. That scheme recognises that a pipeline system may comprise covered and uncovered parts, but the uncovered parts of the system are irrelevant to the determination of the access arrangement applying to the covered pipeline. The total revenue, from which the reference tariffs for the reference services provided using the covered pipeline are determined, is to be the total cost of providing services using the covered pipeline.

Accordingly, the total revenue of the GGP is the total cost of providing pipeline services using the Covered Pipeline. The Covered Pipeline is used to provide services to the GGT JV participants. It is also used to provide negotiated services. In addition, the GGP Access Arrangement offers, subject to there being sufficient spare capacity in the Covered Pipeline, a firm service reference service. The total revenue is, then, the total of the costs of offering to provide, and providing, the reference service, negotiated services and services to the joint venturers using the Covered Pipeline. It is the total of the costs of providing services using the GGP excluding:

(a) the capital costs of those parts of the pipeline system (a second compressor added at Paraburdoo, in 2006, and compressors installed at Wyloo West and at Ned's Creek in 2009) which are uncovered;

(b) the capital costs of the recent expansion for Rio Tinto Iron Ore and for BHP Billiton Iron Ore, pipeline expansion which GGT has elected be uncovered and in respect of which the ERA gave its consent to GGT's election on 30 May 2014; and

(c) the costs of operating and maintaining those parts of the GGP which are uncovered, and the costs of operating and maintaining the expansion for Rio Tinto Iron Ore and BHP Billiton Iron Ore.

GGT has therefore established the total revenue for the Covered Pipeline as the total of:

(a) the return on the projected capital base of the Covered Pipeline;

(b) depreciation of the assets comprising the Covered Pipeline;

(c) the cost of corporate income tax estimated using the forecast revenue from the provision of the reference service, negotiated services and services to the GGT JV participants using the Covered Pipeline; and

(d) the forecast costs of operating the Covered Pipeline.

The projected capital base of the Covered Pipeline has been determined in accordance with rule 77(2). Conforming capital expenditure on the Covered Pipeline has been added to, and depreciation of the assets comprising the Covered Pipeline has been subtracted from, the capital base at the commencement of the current access arrangement period.

The capital base at the commencement of the current access arrangement period was established, in 2012, after Applications Nos 1 and 2 of 2010 were heard by the ERB. It was the capital base of the Covered Pipeline at the commencement of the current period.

3.3 Consistency of approach to calculating total revenue with the national gas objective

The reference tariff determined from the revised total revenue is to be specified in the GGP Access Arrangement; it becomes a provision of the access arrangement. As a provision of the GGP Access Arrangement, the reference tariff must be consistent with the national gas objective, and with the rules in force when the terms and conditions of the access arrangement are revised (rule 100).

In the preceding section of the Supporting Information, GGT explained why its approach to determination of the proposed revised total revenue for the Covered Pipeline is in accordance with the requirements of the NGR. In subsequent sections, GGT sets out the reasons why its determination of the components of total revenue and, in consequence, of the proposed revised reference tariff, are consistent with the requirements of the NGR and the NGL. In this section, GGT sets out the reasons why the critical step in its determination of the proposed revised reference tariff – determination of the revised total revenue – is consistent with the national gas objective. First, we address the specific issue of why the way in which its proposed determination of the capital base is consistent with the national gas objective. We then consider the broader question of whether the allocation of costs between the Covered Pipeline and the uncovered pipeline is consistent with the objective.

GGT's approach to calculation of total revenue ensures that it has a reasonable opportunity to recover at least the efficient costs it incurs in providing reference services. Further, as will be discussed below, this approach ensures efficient use of the existing pipeline capacity, and efficient investment in new capacity.

In particular, the way in which GGT has determined the capital base of the Covered Pipeline, excluding the capital costs of the uncovered pipeline, ensures that it has a reasonable opportunity to recover at least the efficient costs it incurs in providing reference services, and therefore promotes efficient investment in, and efficient operation and use, of natural gas services for the long term interests of consumers of natural gas. It is consistent with the national gas objective.

This consistency of the way in which GGT's approach with the national gas objective further confirms that the approach to total revenue determination under the NGL and the NGR is similar to the approach that was required under the Code.

We now turn to the broader question of whether the method of calculating total revenue for the Covered Pipeline and, in particular, the question of whether the allocation of costs between the Covered Pipeline and the uncovered pipeline, is consistent with the national gas objective. GGT concludes that its method of calculating total revenue is consistent with the national gas objective, and that a reference tariff determined from the total revenue is also consistent with the objective.

Total revenue is to include all costs associated with the provision of services using the Covered Pipeline. GGT therefore includes in total revenue all costs that would be incurred by a prudent service provider in operating the Covered Pipeline on a stand-alone basis. The only costs that are not included in total revenue for the Covered Pipeline are the incremental costs associated with the uncovered capacity.

In addressing the question of whether this approach to calculating total revenue is consistent with the national gas objective, consideration must be given to whether the approach will promote efficient use of, and efficient investment in, natural gas services. In the remainder of this section, we outline two methods of addressing whether the proposed approach promotes efficient use of existing capacity, and efficient investment in new capacity. In both, the relevant dimension of efficiency is allocative efficiency and, not surprisingly, both lead to the same conclusion: GGT's proposed to calculating total revenue for the Covered Pipeline is consistent with the objective.

The first method focuses on whether there is an alternative to the proposed approach to calculation of total revenue which would result in a greater level of use and/or value to users of the capacity of the Covered Pipeline, and which would thereby promote allocative efficiency. For an alternative approach to the calculation of total revenue to promote allocative efficiency, that approach must result in reference tariffs that are:

(a) not greater than the level at which all existing users could procure the same capacity; and

(b) not less than the total of all costs caused by the investment in and use of the relevant service.

GGT's proposed approach to calculating the total revenue to be recovered from users of the covered capacity of the GGP complies with these requirements for allocative efficiency. Under that approach, the forecast revenue which would be earned at the reference tariff is sufficient to cover the cost of providing the reference service, but is no greater than the efficient, standalone cost of providing that service. The approach is, therefore, consistent with the national gas objective (and with the revenue and pricing principles of section 24 of the NGL)

This way of demonstrating that GGT's allocation of costs between the Covered Pipeline and the uncovered pipeline is consistent with the national gas objective is set out more fully in a report from consultant economists, HoustonKemp, which is Attachment 2 to the Supporting Information.

The second method of demonstrating that GGT's allocation of costs is consistent with the national gas objective proceeds from the requirement for economic efficiency that the price of a commodity be equal to the marginal cost of its production.

GGT's proposed approach to the allocation of costs between the Covered Pipeline and the uncovered pipeline allows the prices to be paid for customers of future uncovered expansions to reflect the marginal costs of those expansions, and is likely to promote the efficient use of, and investment in, natural gas services, consistent with the requirements of the national gas objective.

By allowing GGT the flexibility to set prices for new uncovered expansions that are based on the marginal costs, the proposed approach to cost allocation will provide signals to those prospective customers of the costs that they themselves will impose. Efficient investments will not be abandoned simply because those users are forced to pay a share of non-marginal sunk common costs. Situations in which customers inefficiently reduce their use of the pipeline because the price is too high (relative to the costs which they cause to be incurred) will be avoided.

This second way of demonstrating that GGT's approach to calculating total revenue for the Covered Pipeline is consistent with the national gas objective is set out more fully in an expert economist's report from Dr Tom Hird of Competition Economists Group (CEG). Dr Hird's report is Attachment 3 to the Supporting Information.

3.4 Determining the reference tariff for the GGP

In its May 2010 Final Decision on the access arrangement revisions proposal which GGT submitted in March 2009, the ERA required that the reference tariff for the GGP be determined as the forecast total cost of providing the reference service, negotiated services and services to the GGT JV participants using the Covered Pipeline divided by the forecast of the total volume of those services to be provided.

In accordance with the previous ERA approach, determination of the revised reference tariff can proceed using, as a forecast of capacity, that capacity which a user seeking the firm service reference service of the GGP Access Arrangement might be able to access.

If any of GGT's gas transportation agreements for negotiated service provided using the Covered Pipeline were to terminate, or if any of the services provided to the GGT JV participants were to become unutilised, then the capacity which had been used to provide those services would be available to a prospective user seeking access to the reference service.

GGT has included all of the capacity which might become available for reference service provision in the forecast of capacity used to determine the capacity-related component of the proposed revised reference tariff. The forecast of the utilisation of that capacity (throughput) has been used to determine the throughput-related component of the proposed revised reference tariff. Loosely speaking, GGT has determined the proposed revised reference tariff by dividing the forecast total revenue by the total volume of the services forecast to be provided using the Covered Pipeline.

This is consistent with the ERA's past practice of allocating costs equally across all pipeline capacity services (ERA October 2009 Draft Decision, paragraph 741) such that is no requirement for GGT to allocate costs between reference and other services in accordance with the requirements of rule 93. All of the costs of the Covered Pipeline have, in effect, been allocated to provision of the reference service.

With a single reference service, the requirement under rule 95(2) to allocate the total revenue across each of a number of such services does not apply.

3.5 Use of a nominal rate of return and determination of total revenue after tax

Rule 87(4) requires that the allowed rate of return (which is applied to the projected capital base to determine the return included in the total revenue) be a nominal rate of return.

Since 2005, the returns on the projected capital base included in the total revenues from which reference tariffs for the GGP have been determined have been calculated by applying a nominal rate of return to projections of a historical cost capital base.

If the returns on the capital base are calculated as products of a nominal rate of return and a historical cost capital base, GGT has the opportunity to recover, through reference tariffs determined from total revenues including those returns, the efficiently incurred costs of financing the GGP. If a nominal rate of return were applied to a real cost asset base, GGT would not be provided with the opportunity to recover the efficient financing costs of providing reference services. If a nominal rate of return were to be applied to an indexed capital base, GGT may over-recover the allowance for inflation which was included explicitly in the capital base and included, implicitly, in the nominal rate of return.

Rule 87(4) does not, therefore, require any change in the way in which the projected capital base for the GGP is determined, or any change in the way in which the return on that projected capital base is calculated.

However, the nominal rate of return which was previously applied in determining the total revenue was a nominal pre-tax weighted average cost of capital (WACC), and the total revenue for the GGP did not include an explicit cost of tax.

An amendment to rule 76, which was incorporated into the NGR in November 2012, requires that the total revenue include, as one of the building blocks, an estimate of the cost of corporate income tax. Explicit inclusion of the cost of tax in the total revenue is no longer optional as it was under the Code and under earlier versions of the NGR.

Officer has shown that, when nominal cash flows to be discounted include an explicit allowance for tax, the appropriate discount rate is a nominal vanilla WACC.[6] Rule

[6] R. R. Officer (1994), "The Cost of Capital of a Company Under an Imputation Tax System", Accounting and Finance, May, pages 1 – 17.

87(4) therefore requires that the allowed rate of return be determined on a nominal vanilla basis, consistent with the inclusion of the cost of tax in the total revenue determined in accordance with rule 76.

For the determination of the total revenue, GGT has calculated the return on the projected capital base, at the beginning of each regulatory year of the period from 1 January 2015 to 31 December 2019, as the product of a proposed – nominal – allowed rate of return and a projection of the historical cost capital base for the GGP.

Moreover, an explicit allowance for the cost of corporate income tax has been included in the total revenue.

Determination of a proposed allowed rate return is discussed in section 7 of the Supporting Information. The projection of the capital base – its "roll forward" – is summarised in section 6.4, after a discussion of depreciation in section 5. The calculation of the cost of corporate income tax in accordance with the requirements of rule 87A is considered in section 8. The forecast of operating expenditure used in determining the total revenue, and its justification in accordance with the criteria of rule 90, are set out in section 10. The total revenue and determination of the proposed revised reference tariff are then summarised in section 11.

4 Demand for pipeline services

GGT's proposed revisions to the GGP Access Arrangement are to apply during the period from 2015 to 2019. Proposed revised reference tariffs have been calculated from estimates of the costs which GGT expects to incur in providing pipeline services using the Covered Pipeline during this period (see Section 3 above), and from forecasts of the demand for those pipeline services.

This section of the Supporting Information sets out GGT's view of the demand for pipeline services during the period 2015 to 2019, and the capacity and throughput forecasts which have been used in determining the proposed revised reference tariff for that period.

4.1 Capacity and throughput forecasts

The demand for pipeline services provided using the Covered Pipeline is dependent on conditions in international commodity markets, principally the markets for nickel and gold. Users of the pipeline are primarily companies with mining and mineral processing operations with the Pilbara, Mid West and Goldfields-Esperance regions of Western Australia, producing gold and nickel for sale in these international markets.

Some gas is transported for power generation in regional communities, and a small quantity is delivered into the Kalgoorlie distribution system for commercial and residential use in the town.

Capacity and throughput forecasts for the Covered Pipeline for the period 2015 to 2019 are shown in Table 1.

Capacity and throughput forecasts are shown for the current GGT JV participants (Alinta DEWAP, Southern Cross Pipelines Australia, and Southern Cross Pipelines (NPL) Australia), and for users with third party access to the GGP. GGT has taken that capacity (which is used to provide firm service gas transportation) into account when determining the proposed revised reference tariff for the GGP (see section 3.4 above).

The forecasts shown in Table 1 are based on:

(a) user capacity entitlements in existing gas transportation agreements;

(b) GGT expectations concerning termination of existing transportation agreements, and likely new users of the GGP, and,

(c) user advice on, and GGT estimates of, the use of contracted capacity (throughput) in the GGP.

Table 1: Capacity and throughput forecasts: 2015-2019

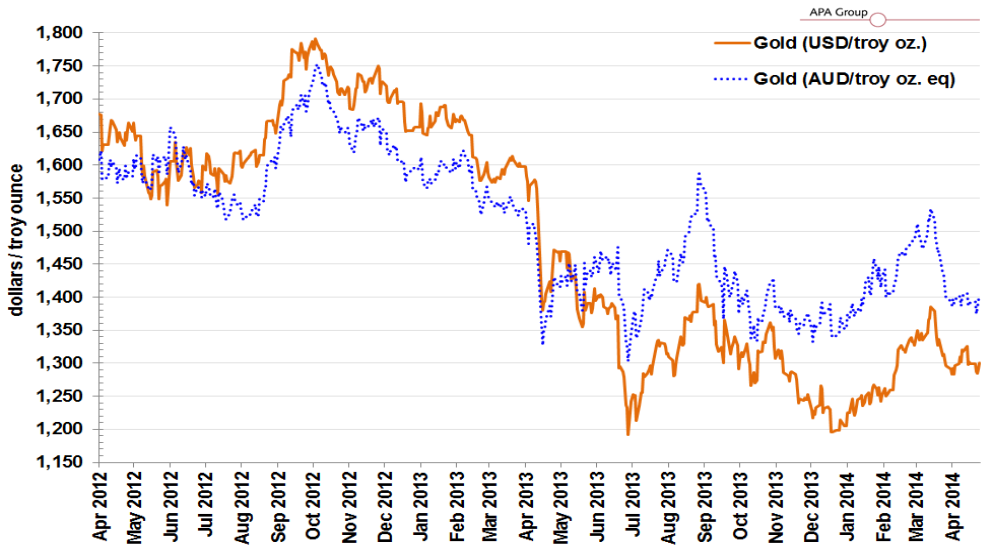
		2015	2016	2017	2018	2019
Reserved capacity						
[redacted]						
	TJ/d	**94.79**	**105.33**	**105.04**	**105.04**	**105.04**
Throughput						
[redacted]						
	TJ/d	**71.42**	**78.04**	**78.04**	**78.04**	**78.04**

4.2 Gold mining

[redacted]

The decline in the price of gold during 2013 (see Figure 1) has threatened the commercial viability of Australian producers causing some to find ways of cutting costs, causing others to place mining operations on care and maintenance, and causing some to close operations.[7] This outlook is reflected in the forecasts for the gold mining operations shown in Table 2.

Figure 1: Gold price 2012-2014



[redacted]

Apex Minerals' gold mining operation at Wiluna was one of the casualties of the fall in the gold price in 2013. Apex went into administration in July 2013, and has subsequently been wound up. Capacity provided under a gas transportation agreement with Apex (3.5 TJ/d) was available for third party access, and is shown on the GGP spare capacity register. [redacted] No other prospective user is currently seeking capacity at Wiluna, and the spare capacity is not expected to generate revenues during the next access arrangement period.

[7] Bureau of Resources and Energy Economics, *Resources and Energy Quarterly*, March Quarter 2014, pages 73-74.

The AngloGold Ashanti-Independence joint venture Tropicana mine was one of the few new major gold mining developments in Australia during 2013. Tropicana has annual capacity of around 14 tonnes and is one of the largest gold mines to open in recent years.[8] In July 2014, gas transportation agreements were concluded with AngloGold for the transport of gas to Leonora. [redacted].

No other prospective user is currently seeking a substantial tranche of capacity in the GGP. [redacted]

Both the capacity [redacted] which is expected to be unused during 2015 [redacted], and the capacity released by the winding up of Apex Minerals [redacted], have been excluded from the capacity forecasts used to determine the proposed revised reference tariff for the GGP.

4.3 Nickel

[redacted]

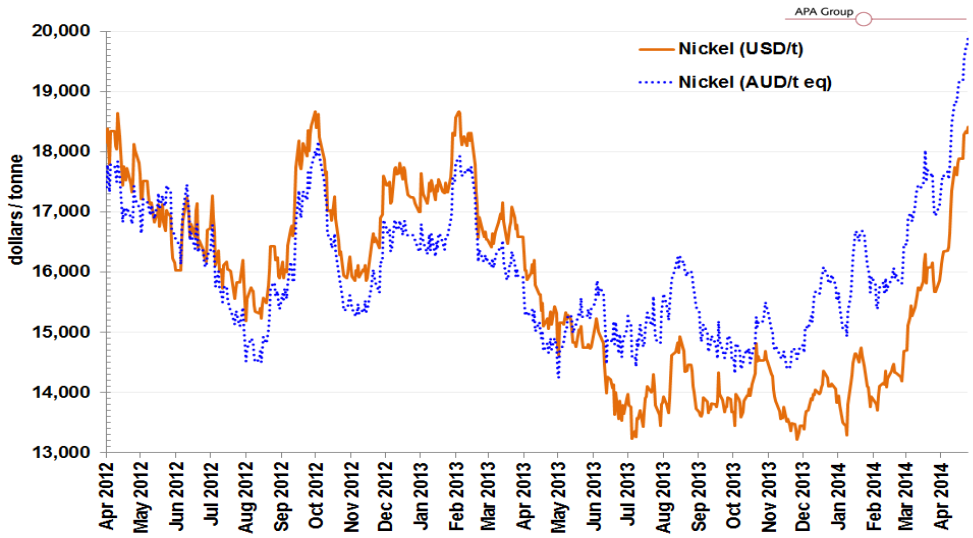
Nickel prices were depressed during 2013 (see Figure 2) as a result of refined production exceeding consumption.[9] However, prices have begun to rise again 2014. This seems to be occurring even though world refined nickel production is forecast to fall. A lower level of production is expected to continue into 2015, until existing stocks (built up, in part, as a pre-emptive response to an Indonesian Government ban on the export of unprocessed raw materials which came into effect on 12 January 2014) have run down. With lower stocks, and consumption growth at around 1%, prices could increase further over the period to 2019 as refined production grows to meet demand principally from China. The price effect of the growth in demand may be attenuated by increased production from the Philippines and Indonesia.[10]

8 Ibid., page 74.

9 Ibid., page 96.

10 Ibid., pages 96-97.

Figure 2: Nickel price: 2012-2014



Uncertainty in the market outlook internationally is reflected in uncertainty about nickel mining and processing operations in Western Australia.

[redacted][11].

[redacted][12].

[redacted]

[redacted]

[11] [redacted]

[12] Ibid.

[redacted]

4.4 Other uses of capacity in the Covered Pipeline

Over 75% of the capacity of the Covered Pipeline is contracted to companies using gas in gold and nickel mining and processing operations. The remainder of the total capacity (some 22 TJ/d is reserved for power generation and gas distribution in Kalgoorlie. [redacted]

[redacted]

[redacted]

5 Depreciation

GGT first submitted a proposed access arrangement for the GGP for regulator approval in 1999. It was submitted for approval under the Code. Sections 8.32, 8.33 and 8.35 of the Code governed depreciation.

For total revenue and reference tariff determination for this first proposed access arrangement, GGT proposed that depreciation be calculated using a units of production method. This was not accepted by the regulator (then the Independent Gas Pipelines Access Regulator) who required, in his April 2001 Draft Decision, use of the straight line method:

The Regulator considers that the use of accelerated depreciation has not been adequately justified and that the Depreciation Schedule for the Goldfields Gas Pipeline should be determined on the basis of a straight line depreciation methodology.[13]

GGT subsequently incorporated the straight line method into its revised access arrangement proposal. An amended Draft Decision in July 2004, made by the ERA, noted at paragraph 358:

. . . taking into account that the effect of [historical cost accounting methodology used by GGT] is to affect the time path of tariffs but not the present value of returns to GGT over the life of the pipeline, and that the required amendments to the Access Arrangement under this Amended Draft Decision result in a reduction in tariffs for the pipeline despite the accelerated depreciation, the Authority considers that the historical-cost, straight-line depreciation methodology used by GGT for the purposes of the tariff calculation described in its submission of 17 December 2002 complies with the requirements of the Code.

In its May 2005 Final Decision (in paragraph 315), the ERA confirmed its position in the amended draft decision, noting in paragraph 314 that:

The straight-line depreciation methodology is consistent with standard practice for regulated pipelines in Australia . . .

When approving the GGP Access Arrangement in July 2005, the ERA approved the use of the straight line method of depreciation for determination of the total revenue and the setting of the reference tariff for the pipeline.

Proposed revisions to the GGP Access Arrangement were submitted for regulator approval in 2009 and, in its October 2009 Draft Decision, the ERA reaffirmed, in paragraph 364, the use of straight line depreciation as meeting the requirements of the Code:

In its Final Decision in relation to the current Access Arrangement, the Authority considered certain depreciation methodologies. It took the view that Depreciation

[13] Independent Gas Pipelines Access Regulator, *Draft Decision Access Arrangement Goldfield Gas Pipeline*, April 2001, Part B, page 159.

calculated by an historic cost, straight-line methodology was in keeping with the principles set out in section 8.33 of the Code. The Authority notes that GGT proposes to continue with this Depreciation methodology.

The ERA's May 2010 Final Decision did not explicitly address the method of depreciation, but its required amendments reflected the use of straight line depreciation in determination of the total revenue and in the setting of the reference tariff.

The use of straight line depreciation for the GGP was originally prescribed by the ERA's predecessor, the Independent Gas Pipelines Access Regulator. The ERA continued to find the use of straight line depreciation as being in accordance with the requirements of the Code, and has acknowledged that this use is "standard practice" in economic regulation.

The Code was replaced by the NGR when the National Gas Access (Western Australia) Act came into effect in 2010, and rules 88, 89 and 90 now govern depreciation. Rules 88 and 89 are similar in form and effect to sections 8.32, 8.33 and 8.35 of the Code. There was no section in the Code directly equivalent to rule 90. Rule 90 deals with specific issues arising in the calculation of depreciation for rolling forward capital base from one access arrangement period to the next.

In this section of the Supporting Information, GGT assesses the straight line method against the requirements of the NGR and finds that it meets the requirements of rules 88 and 89.

GGT proposes the continued use of straight line depreciation for the purpose of determining the total revenue and the reference tariff for revision of the GGP Access Arrangement. Straight line depreciation is a fundamental element in the value proposition on which the gas transportation business of the GGP has been built, and is fundamental to pipeline financing.

5.1 Rules governing depreciation

Rules 88 and 89 are as follows:

88 Depreciation schedule

(1) The depreciation schedule sets out the basis on which the pipeline assets constituting the capital base are to be depreciated for the purpose of determining a reference tariff.

(2) The depreciation schedule may consist of a number of separate schedules, each relating to a particular asset or class of assets.

89 Depreciation criteria

(1) The depreciation schedule should be designed:

(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the ERA permits, for inflation)); and

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

(2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:

(a) the present market for pipeline services is relatively immature; and

(b) the reference tariffs have been calculated on the assumption of significant market growth; and

(c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

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

Rule 88 requires a depreciation schedule for the purpose of determining a reference tariff.

Rules 89(1) and 89(2) set out broad criteria which guide the design of that schedule.

Rule 89(3) limits the regulator's discretion under rules 89(1) and 89(2). The regulator may not withhold its approval of a proposed depreciation schedule if it is satisfied that:

(a) the proposal complies with the applicable requirements of the NGL and the NGR; and

(b) is consistent with applicable criteria (if any) prescribed by the NGL and the NGR.

The example of the operation of limited discretion set out in rule 40(2) refers specifically to depreciation. Even if the regulator is of the view that a change would achieve more complete conformity between the depreciation schedule and the

principles and objectives of the NGL and the NGR, that view cannot be given effect in the decision making process if the service provider's proposal is compliant with the applicable requirements of the NGL and the NGR, and is consistent with applicable criteria prescribed by the NGL and the NGR.

5.2 Rule 87 has no implications for the GGP depreciation schedule

If a nominal rate of return is applied to a depreciated historical cost capital base, then the present value of the resulting return plus depreciation stream is equal to the present value of the investment represented by the capital base. This is the case for any method of calculating depreciation.[14]

Rule 87(4) requires use of a nominal rate of return when determining total revenue. There was no similar requirement in the Code, but a nominal rate of return has been used in determination of the total revenue for the Covered Pipeline since the GGP Access Arrangement was approved in 2005. That nominal rate of return was applied to a historical cost asset base for the pipeline.

The requirement of rule 87(4), that the allowed rate of return now be determined on a nominal vanilla basis, does not require a change to the depreciation method used in determining the total revenue of the Covered Pipeline.

5.3 Straight line depreciation is consistent with the requirements of the NGR

The use of straight line depreciation has previously been accepted by the ERA in the determination of the total revenue and the reference tariff for the Covered Pipeline. GGT has assessed the straight line method against the requirements of the NGR. We begin with assessment against the more mechanical aspects of depreciation (rule 88, and rules 89(1) (b), (d) and (c)), and then address the broader commercial and economic requirements of rules 89(1)(e) and 89(1)(a).

5.3.1 Rule 88: depreciation schedule

Rule 88 requires a depreciation schedule which sets out the basis on which the assets comprising the capital base are to be depreciated, and states that the required schedule may consist of a number of separate schedules, each relating to a particular asset or class of assets.

GGT has adopted a depreciation schedule whereby, for the purpose of determining the reference tariff for the Covered Pipeline, depreciation is calculated for each of eight classes of depreciable assets.

A separate schedule exits for each of the eight asset classes. For the assets in each class, depreciation is determined for the period of the expected economic life of those assets by dividing the value of assets in the class, at the time of their inclusion in the

[14] See Richard Schmalensee (1989), "An Expository Note on Depreciation and Profitability Under Rate of Return Regulation", Journal of Regulatory Economics, 1(3), pages 293-298.

capital base, by the life. For any year beyond the expected economic life the depreciation is zero. That is, the depreciation schedule provides for the straight line depreciation for each of the eight classes of depreciable assets.

The asset classes, and the expected economic lives over which they are depreciated, are shown in Table 2.

Table 2: Depreciation: asset classes and expected economic lives

Asset class	Economic life (years)
Pipeline and laterals	70
Main line valve and scraper stations	50
Compressor stations	30
Receipt and delivery point facilities	30
SCADA and communications	15
Cathodic protection	15
Maintenance bases and depots	50
Other assets	10

The straight line depreciation schedule which GGT has used in determining the proposed revised reference tariff for the Covered Pipeline is in accordance with the requirements of rule 88.

5.3.2 Rule 89(1)(b): depreciation over economic life

Rule 89(1)(b) requires that the depreciation schedule be designed so that each asset or group of assets is depreciated over the expected economic life of that asset or group of assets.

GGT's use of a depreciation schedule whereby assets are depreciated using the straight line method provides for the return of investment on an asset or group of assets over the economic life of that asset or group of assets.

Straight line depreciation is in accordance with the requirement of rule 89(1)(b).

5.3.3 Rule 89(1)(d): asset depreciated only once

Rule 89(1)(d) requires that the depreciation schedule be designed so that an asset or group of assets is depreciated only once. That is, the amount by which the asset or group of assets is depreciated over its economic life must not exceed the value of the asset or group of assets at the time of its inclusion in the capital base.

Straight line depreciation starts with the initial value of an asset or group of assets (the value of the asset or group of assets at the time of its inclusion in the capital base) and, in each year during the expected economic life, subtracts an amount equal to that initial value divided by the life of the asset or group of assets in question. If the asset or group of assets survives beyond its expected economic life, depreciation in all subsequent years is zero. The initial value of the asset or group of assets is progressively reduced, year by year, by a series of amounts which are, in total over

the expected economic life, equal to the initial value of the asset or group of assets. With a straight line depreciation schedule, an asset or group of assets is depreciated "only once".

Straight line depreciation is in accordance with the requirement of rule 89(1)(d).

5.3.4 Rule 89(1)(c): change in expected economic life

Rule 89(1)(c) requires that the depreciation schedule be designed so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset or a particular group of assets.

Straight line depreciation starts with the initial value of an asset or group of assets (the value of the asset or group of assets at the time of its inclusion in the capital base) and, in each year during the expected economic life, subtracts an amount equal to this initial value divided by the economic life of the asset or group of assets in question. If the expected economic life of the asset or group of assets changes, straight line depreciation is easily modified to reflect the change. The written down value of the asset or group of assets (the initial value less accumulated depreciation) at the time the expected economic life changes is depreciated during the remainder of the new economic life, by applying the straight line method over the remaining years of life, after which depreciation is zero. If there is no further change in the expected economic life, the accumulated depreciation over the entire life will be equal to the initial value of the asset or group of assets, and the asset or group of assets will be depreciated only once.

With straight line depreciation, the depreciation schedule is easily adjusted to reflect changes in the expected economic lives of assets or groups of assets. A straight line depreciation schedule is consistent with the requirement of rule 89(1)(c).

5.3.5 Rule 89(1)(e): allowing for the service provider's need for cash flow

Rule 89(1)(e) requires that the depreciation schedule be designed so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

The building block approach to total revenue determination, and the tariff provisions of Division 8 of Part 9 of the NGR, operate to ensure that a service provider is provided with a reasonable opportunity to recover at least the efficient costs of providing pipeline services. This is achieved, in part, by the explicit identification in rule 76 of the principal costs of pipeline service provision, and the allocation of those costs, in accordance with rules 93 and 95, to reference tariffs for recovery from pipeline users.

The building blocks and the scheme of Division 8 provide for recovery of the estimated cost of tax and forecast operating expenditures. The recovery of these components of total cost via reference tariffs should, in the normal circumstances of business operation, allow for the service provider's reasonable needs for cash flow to meet non-capital and other costs. (By the normal circumstances of business operation, we mean the circumstances of the business as a going concern, neither expanding, and

having additional requirements for finance, nor contracting and experiencing financial distress.)

The recovery of a return on the projected capital base should allow for the service provider's reasonable needs for cash flow to provide investors with the return they require on the investment they have made in the service provider's business.

The recovery, via reference tariffs, of the depreciation component of total revenue, provides the service provider with the cash flow required to provide the return of investment to investors when that is required.

A business will typically be financed with a mix of short term debt and long term debt and, at any time, is likely to have a requirement to repay some of this debt. In the normal circumstances of business operation, cash flow from depreciation, which recovers the total investment financed by equity and debt, should be sufficient to meet this requirement for debt repayment.

Straight line depreciation is a simple rule for providing a business with a constant cash flow over the life of an asset or group of assets for the return of investment, thereby facilitating the management of debt repayment. In this respect, straight line depreciation is superior to alternatives, like the annuity method and the method of the AER's post tax revenue model, which artificially defer the return of investment to the later years of asset life, and defer the cash flow required for debt servicing.

Straight line depreciation allows for the service provider's reasonable needs for cash flow to repay debt.

5.3.6 Rule 89(1)(a): reference tariffs which promote efficient growth in the market

Rule 89(1)(a) requires that the depreciation schedule be designed so that reference tariffs vary, over time, in a way that promotes the efficient growth in the market for reference services. This may involve deferral of a substantial proportion of depreciation (in accordance with rule 89(2)) when:

(a) the market for pipeline services is relatively immature;

(b) reference tariffs have been calculated on the assumption of significant market growth; or

(c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

Market for services provided using the Covered Pipeline is mature

The market for pipeline services using the Covered Pipeline is a relatively mature market. It is not a market which is growing rapidly, or which has prospects for continuous growth arising from innovation and new product development, or from population growth or industrial development in the regions served by the pipeline.

The principal users of the Covered Pipeline are the larger mine operators and mineral processors along the route of the GGP, with whom GGT has been contracting and recontracting for over a decade. These users supply into highly competitive international markets and, in their negotiations for pipeline services, are focused on service tailored to the specific requirements of their operations and on service provision at minimum cost.

Innovation and new product development may not be providing opportunities for growth, but they are contributing to that state of the market for pipeline services. They are facilitating, in the regions served by the GGP, energy supply chains based on compressed natural gas and liquefied natural gas that do not require the pipeline transportation of gas.

GGT has not seen continuous growth in the market for pipeline services provided using the GGP since the early years of pipeline operation. Construction of the GGP commenced in 1995 and was completed in 1996, with gas first delivered to Kalgoorlie (and Kambalda) in October 1996. The initial users of the pipeline were the initial GGT JV participants, who had substantial mining and mineral processing operations along the route of the pipeline. The initial joint venture participants anticipated demand for pipeline services other than their own, and undertook, in their agreement with the State of Western Australia – the GGP State Agreement – to provide third party access to unutilised and developable capacity in the GGP.

Over the next four years, a number of third party users contracted with GGT for pipeline services and, by 2000, the GGP's capacity was fully contracted. To meet additional demand for pipeline services, GGT had to develop capacity in the GGP. The addition of compression at Wiluna, during 2000, allowed the supply of gas to the town of Esperance in 2001 via the then newly constructed Kambalda to Esperance Pipeline.

The capacity of the GGP was subsequently expanded by the installation of a second compressor at Paraburdoo (in 2006), and by the construction of new compressor stations at Wyloo West and Ned's Creek (in 2009). The recent installation of additional compressors at Yarraloola and Paraburdoo, and construction of a new compressor station at Turee Creek, have further expand the capacity of the pipeline.

The addition of compression has significantly expanded pipeline capacity but, in each case, expansion has been effected by a discrete – “lumpy” – investment. Expansion has been undertaken to meet the specific needs of users who were prepared to underwrite the investment with long term gas transportation agreements.

For over a decade, the Covered Pipeline has been fully utilised, but it could be expanded to accommodate future growth in the demand for pipeline services. Further investment in capacity would be required if the GGP were to accommodate significant future growth in demand.

No growth in the demand for reference and negotiated services provided using the Covered Pipeline is expected during the period 2015 to 2019 (indeed, some a decline in demand is forecast), and the reference tariff has not been calculated on the assumption of significant market growth.

There is, in these circumstances, no justification for deferring a substantial proportion of the return of investment in – the depreciation of – the assets which comprise the Covered Pipeline.

The straight line depreciation schedule which GGT has used, and proposes to continue to use, does not effect such a deferral of the return of investment.

Depreciation, reference tariffs and efficient growth in the market

In the economic regulatory regime of the NGR, depreciation is the allocation of previously incurred (capital) expenditure to future periods for recovery via a reference tariff.

Depreciation is not, in the regime of the NGR, a residual to be calculated after the reference tariff has been determined, as would be the case if the tariff were to be set to equate, over the expected economic life of the assets comprising the covered pipeline, the present value of forecast revenues with the present value of forecast costs (excluding any allowance for depreciation). In this case, depreciation (usually referred to as economic depreciation) varies with demand for the service: with the tariff fixed, the return of investment is low when the demand for the service is low, and the return of investment is high when demand is high.

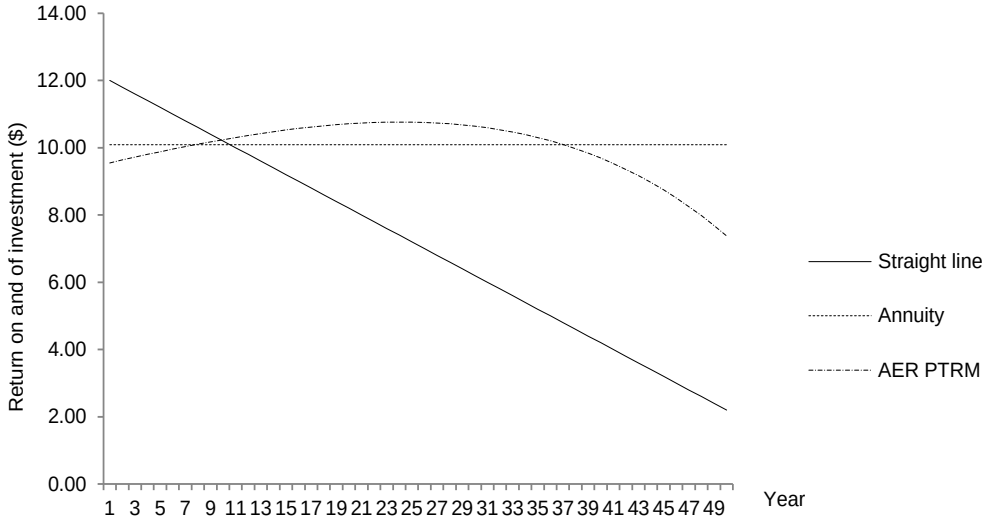
Nor is depreciation, in the regime of the NGR, a cost associated with the physical deterioration of the assets which comprise a covered pipeline, or a cost attributable to the obsolescence of those assets.

When depreciation is the allocation of a past capital cost to future periods for recovery via a tariff, there are many simple rules which can be used to make the allocation. Some of those rules (for example, units of throughput and double declining balance), if used to determine the tariff, would accelerate the return of investment relative to other methods. Others (for example, the annuity method and the method of the AER's post-tax revenue model) would defer the return of investment until later years in the life of the covered pipeline.

Over the long term, the use of any one of these simple rules for depreciation may, or may not, promote growth in the market for reference services. Each method has a different effect on the level of the reference tariff.

Figure 3 illustrates the return on and return of investment obtained using each of three simple rules for depreciation: straight line, annuity, and the method of the AER's post-tax revenue model (AER PTRM method). In each case, the initial value of the asset depreciated is $100, and the asset life is 50 years. Where relevant, the rate of return is 10.0%.

Figure 3: return on and of investment with different depreciation schedules



Straight line depreciation provides a constant return of investment which, over time, lowers the return on and of investment relative to the annuity and AER PTRM methods. Other things being equal, this leads to the lowering of tariffs in the longer term. The AER PTRM method defers the return of investment (keeping the return on investment high) and, other things being equal, leads to lower tariffs early in the asset's economic life, and to relatively higher tariffs in the longer term. The annuity method keeps the return on and of investment constant over the life of the asset, and has the effect of levelling the tariff.

In economic terms, the demand for reference services is a derived demand: it is a demand which derives from the demand for gas and, ultimately, from the demand for products or services produced using gas. Pipeline users do not demand the reference service in its own right. They require it as an input into the production of products and services which either they, themselves, consume, or which they will sell, possibly through an extended supply chain, to final consumers. Demands for the products and services produced using gas are driven by their prices relative to the prices of substitutes and complements. The prices of those products and services produced using gas will, in turn, be determined, at least in part, by their costs of production, including the cost of delivered gas. The cost of gas transportation is a component of that cost of delivered gas.

If the cost of delivered gas is high, the costs of the products and services produced using gas will be higher than would otherwise have been the case, and the demand for those products and services will be lower. In consequence, the demands for delivered gas, and for gas transportation service, will be lower. If the cost of delivered gas is low, the costs of production will be lower than would otherwise have been the case, the demand for products and services produced using gas will be higher, the demand for delivered gas will be higher, and the demand for gas transportation service will be higher.

Growth in the market for reference services is, therefore, driven by the growth in demand for gas which is, in turn, driven by the growth in demand for the products and services produced using that gas. Whether there is growth in demand for the products and services produced using gas will depend on, among other things, the price the producers of those products and services pay for delivered gas. Whether, in turn, the delivered price of gas is high or low will depend on both the price of gas (the commodity) and the tariff for gas transportation. Growth in the market for reference services can be expected when the price of delivered gas is – relatively – low because:

(a) the price of gas is low and the tariff for gas transportation is low;

(b) the price of gas is low but the tariff for gas transportation is high; or

(c) the price of gas transportation is high but the price of gas is low.

Whether a depreciation schedule used in setting a reference tariff promotes, or does not promote, growth in the market for reference services will depend on, among other things, the price of gas.

In Western Australia, the price of gas is expected to rise over the next decade, and is expected to rise in the longer term as more marginal reserves are developed.

In its Gas Statement of Opportunities, published in January 2014, the Western Australian Independent Market Operator (IMO) advised:

. . . gas prices will rise slowly between 2014 and 2023 due to increases in LNG netback prices as the linkage between average gas prices and LNG netback prices increases with the commencement of Gorgon and Wheatstone LNG export facilities, which are expected to be operational in 2015 and 2016. The different scenarios of price forecasts represent a likely range of average new contract prices for the 2014 to 2023 period.[15]

The IMO is forecasting wellhead gas prices to rise from $6.19/GJ in 2014 to $7.90/GJ in real (inflation adjusted) terms in 2023.

Growth in the market for reference services should, in these circumstances, be promoted by a declining pipeline transportation tariff determined using straight line depreciation. It is unlikely to be promoted by a rising transportation tariff determined using a depreciation schedule (such as that of the AER PTRM method) which defers the return of investment.

GGT's use of straight line depreciation in determination of a reference tariff can be expected to promote growth in the market for the Firm Service reference service provided using the Covered Pipeline.

However, rule 89(1)(a) requires more than growth in the market for the reference service; it requires efficient growth in that market. Whether a reference tariff varies,

[15] Gas Statement of Opportunities, January 2014, pages 63 - 64.

over time, in a way which promotes efficient market growth depends on the way in which the tariff is structured.

In circumstances where the average cost of service provision declines as volume increases, a tariff set equal to marginal cost (as required for the economic efficiency of competitive markets) will be below average cost and will offer the service provider the prospect of losses on service provision.[16] If the service provider is a state-owned entity, these losses might be subsidised from tax receipts, allowing a price to be set consistent with the requirements for economic efficiency. If, however, the service provider is privately owned, it will not usually be subsidised by the state (no mechanism for subsidy is provided in the regime of the NGL and the NGR) and, if service provision is to proceed, it must be at a price different from marginal cost.

That price can be established as a two-part tariff comprising:

(a) a fixed component, set so that the user pays, in total, an amount equal to the total cost of supplying the service; and

(b) a variable component based on marginal cost.[17]

The fixed component of this two-part tariff is independent of the volume of use of the service; it is essentially an access fee. The variable component is the value of the resources the user will consume in choosing to use an additional unit of service. It signals the value of the resources which might be used in another use, or their value to another user, as required for efficiency.

Now, depreciation, along with the return on investment:

. . . is a function of time instead of the rate of utilization. To the extent that such costs are truly fixed, they do not belong in the computation of marginal cost, for the purposes of economically efficient pricing. Moreover, even to the extent that depreciation does vary with use, what belongs in the marginal cost calculation is not the book cost, the writing off of investment costs historically incurred, but the amount by which this and other capital costs will be higher than they would otherwise be in the future by virtue of the incremental production in question. It is for the higher future costs or the decline in future values – not for fixed, historically sunk costs – that the marginal production is causally responsible; it is only the future, and not the past, costs that will be saved if production is not undertaken.[18]

If a reference tariff is structured as a two part tariff, if it is to recover the service provider's efficient costs, and if the tariff is to promote efficiency in the market for a reference service, then depreciation must be recovered via the fixed component of the tariff, and not the variable component. The variable component must reflect the forward looking marginal cost of service provision at the time at which it is set (and will

16 Declining average cost is characteristic of natural monopolies such as gas transmission pipelines.

17 See R. H. Coase (1946), "The Marginal Cost Controversy", Economica, New Series, 13(51): pages: 169-182.

18 Alfred E. Kahn (1991), *The Economics of Regulation: Principles and Institutions*, Volume 1, Cambridge, Massachusetts: MIT Press, pages 72-73.

not include depreciation which is an allocation of past capital costs to future periods). If the reference tariff is also to promote growth in the market for the reference service then, as discussed above, the tariff should decline over time as the delivered cost of gas rises.

In the case of the Covered Pipeline, the reference tariff is a two part tariff: it has two fixed components, and a single, throughput-related, variable component. By providing for the recovery of depreciation through the fixed components of the tariff, and not through the variable component, GGT has sought to structure a tariff consistent with efficiency in the market for the Firm Service reference service. By proposing the use of straight line depreciation in circumstances where the cost of gas is expected to rise, GGT has sought to promote growth in the market for the reference service. The use of straight line depreciation, together with a two part tariff structure, allows the reference tariff to vary, over time, in a way that promotes efficient growth in the market for reference services in accordance with the requirement of rule 89(1)(a).

Use of a two part tariff and a depreciation schedule which either accelerated, or deferred, the return of investment may be consistent with the requirement for efficiency. However, in circumstances where the price of gas is expected to increase over time, it would not promote growth in the market for the reference service. It would not promote efficient growth in the market for reference services in accordance with the requirement of rule 89(1)(a).

5.4 GGT's proposed use of straight line depreciation

Since 1 August 2005, when the GGP Access Arrangement first had effect, depreciation for the purpose of determining the total revenue has been calculated by applying the straight line method to the historical cost capital base of the GGP.

GGT has therefore determined the total revenue and reference tariff for the proposed revisions to the GGP Access Arrangement by applying the straight line method of depreciation to a historical cost capital base.

Use of the straight line method of depreciation met the requirements of the Code. It also meets the requirements of rules 88 and 89.

GGT has sought the advice of consultant economists HoustonKemp on the issue of depreciation. HoustonKemp support the continued use of straight line depreciation for the GGP. Their report is Attachment 4 to the Supporting Information.

6 Actual and projected capital expenditures, and roll forward of the capital base

The two largest components of total revenue for the Covered Pipeline are the components representing the return on, and the return of, investment. They are:

(a) the return on the projected capital base; and

(b) depreciation of the projected capital base.

The projected capital base, in respect of which the return and depreciation are to be determined, is to be established from the capital base set at the commencement of the current access arrangement period and approved by the regulator for use in determining the current reference tariff.

Conforming capital expenditures made during the current access arrangement period are added to the capital base set at the commencement of that period, and depreciation during the period – the return of capital – is subtracted. If appropriate:

(a) amounts may be added to the capital base in accordance with rules 82 (capital contributions), 84 (speculative capital expenditure) and 86 (re-use of redundant assets); and

(b) the value of redundant assets, and of pipeline asset disposals, is to be subtracted.

Through this process of "roll forward" the opening capital base for the next access arrangement period is established.

The projected capital base is then established in a similar process, adding conforming capital expenditure forecast for the next access arrangement period, subtracting forecast depreciation for that period, and adjusting for forecast asset disposals.

In this section of the Supporting Information, GGT:

(a) notes the rules governing roll forward of the capital base;

(b) summarises capital expenditure and depreciation over the current access arrangement period (2010 to 2014);

(c) sets out its roll forward of the capital base to commencement of the access arrangement period (that is, to 1 January 2015);

(d) summarises forecast capital expenditure and depreciation over the arrangement period (2015 to 2019); and

(e) sets out the calculation of the projected capital base over the access arrangement period.

6.1 Rules governing roll forward of the capital base

When an access arrangement period follows immediately on the conclusion of the preceding access arrangement period, the opening capital base at the commencement of the later period is to be (in accordance with rule 77(2)):

(a) the opening capital base at the commencement of the preceding access arrangement period, adjusted for any difference between estimated and actual capital expenditure included in that opening capital base; plus

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

(c) any amounts for capital expenditure to which a user has contributed, previously non-conforming (speculative) capital expenditures which have become conforming, and the value of any previously redundant assets now able to be re-used; less

(d) depreciation over the preceding access arrangement period; less

(e) the value of redundant assets identified during the preceding period; and less

(f) the value of any pipeline assets disposed of during the preceding period.

The projected capital base for the access arrangement period is, then (in accordance with rule 78):

(a) the opening capital base for the later period established in accordance with rule 77(2); plus

(b) forecast conforming capital expenditure for the period; less

(c) forecast depreciation for the period; and less

(d) the forecast value of any pipeline assets to the disposed of during the period.

Conforming capital expenditure which is made during the preceding access arrangement period, or which is forecast to be made during the access arrangement period, must satisfy the following criteria:

(a) the 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 (rule 79(1)(a)); and

(b) capital expenditure justified on one of the following grounds:

  (i) the overall economic value of the expenditure is positive (rule 79(2)(a));

  (ii) the present value of the expected incremental revenue to be generated exceeds the present value of the capital expenditure (rule 79(2)(b));

(iii) the capital expenditure is necessary:

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

(B) to maintain the integrity of the services; or

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

(D) to maintain the capability to meet levels of demand for service at the time the expenditure is made (rule 79(2)(c)).

6.2 Opening capital base at commencement of the preceding access arrangement period

In its decision on Applications No. 1 and No.2 of 2010, the ERB determined that the reference tariff for the Covered Pipeline should be established by financial modelling for the period 20 August 2010 to 31 December 2014 (and not for the period 1 January 2010 to 31 December 2014). The opening capital base at the commencement of the preceding access arrangement period is, then, the opening capital base established for the Covered Pipeline at 20 August 2010. That opening capital base was $442.585 million.

This opening capital base was calculated using a forecast of capital expenditure ($8.721 million) for 2010. The actual expenditure was $0.664 million. When re-calculated using this actual capital expenditure, the opening capital base at 20 August 2010 is as shown in Table 3.

Table 3: Opening capital base at 20 August 2010

	$ million
Pipeline and laterals	366.958
Main line valve and scraper stations	7.013
Compressor stations	44.580
Receipt and delivery point facilities	2.028
SCADA and communications	2.109
Cathodic protection	1.655
Maintenance bases and depots	6.159
Other (depreciable) assets	1.790
Non-depreciable assets	3.823
Opening capital base at 20 August 2010	**436.116**

6.3 Capital expenditure over the preceding access arrangement period

Capital expenditure on the Covered Pipeline during the period 1 January 2010 to 31 December 2014 is summarised in Table 4.

The expenditures for 2010 to 2013 are actual expenditures. The expenditure for 2014 is a forecast comprising actual expenditure for the period 1 January 2014 to 31 March 2014, and an estimate for the remainder of the year.

Table 4: Capital expenditure by asset class: 2010-2014

	2010	2011	2012	2013	2014
	$ million	$ million	$ million	$ million	$ million
Pipeline and laterals	-0.083	0.000	0.000	0.026	0.000
Main line valve and scraper stations	0.000	0.000	0.000	0.000	0.000
Compressor stations	0.431	0.047	0.259	0.395	0.909
Receipt and delivery point facilities	0.000	0.000	0.000	0.320	0.174
SCADA and communications	0.182	0.364	0.727	0.473	0.866
Cathodic protection	0.000	0.000	0.000	0.000	0.000
Maintenance bases and depots	0.089	0.000	0.000	1.320	0.091
Other (depreciable) assets	0.045	0.023	0.026	0.567	0.951
Non-depreciable assets	0.000	0.000	0.000	0.000	0.000
	0.664	**0.435**	**1.012**	**3.101**	**2.991**

The items which make up the expenditures in Table 4, and the reasons why those expenditures are conforming capital expenditures (in accordance with the requirements of rule 79), are set out in Attachment 5 to the Supporting Information.

That part of the capital expenditure for 2010 which is estimated to have been made during the period 20 August 2010 to 31 December 2010 has been added to the opening capital base shown in Table 3 for the purpose of capital base roll forward.

6.4 Depreciation 2010-2014

Depreciation during the period 2010-2014 is shown in Table 5.

Table 5: Depreciation 2010-2014

	2010	2011	2012	2013	2014
	$ million	$ million	$ million	$ million	$ million
Pipeline and laterals	6.811	6.811	6.811	6.811	6.811
Main line valve and scraper stations	0.207	0.208	0.208	0.208	0.208
Compressor stations	2.498	2.735	2.850	2.877	2.906
Receipt and delivery point facilities	0.109	0.112	0.114	0.116	0.118
SCADA and communications	0.104	0.198	0.324	0.453	0.485
Cathodic protection	0.119	0.207	0.297	0.300	0.302
Maintenance bases and depots	0.178	0.179	0.179	0.180	0.180
Other assets	0.212	0.709	0.915	0.967	1.018
	10.238	**11.159**	**11.699**	**11.913**	**12.029**

The depreciation in Table 5 has been calculated, using the straight line method, from the forecast of capital expenditure used to determine the revised reference tariff for the period 2010 to 2014 (and not from actual capital expenditure for that period).

That part of depreciation for 2010 which is estimated to have been made during the period 20 August 2010 to 31 December 2010 has been subtracted from the opening capital base shown in Table 3 for the purpose of capital base roll forward.

Since the actual capital expenditure for the period 2005 to 2009 was less than forecast, an adjustment has been made for "over-depreciation". This adjustment has been calculated, and applied, in the way in which the ERA calculated and applied an adjustment for over-depreciation at the end of 2009. The components of the over-depreciation adjustment are shown in Table 6.

Table 6: Over-depreciation adjustment 2010

	$ million
Pipeline and laterals	0.000
Main line valve and scraper stations	0.000
Compressor stations	0.125
Receipt and delivery point facilities	0.000
SCADA and communications	0.066
Cathodic protection	0.000
Maintenance bases and depots	0.000
Other assets	0.196
	0.387

6.5 Roll forward of the capital base to commencement of access arrangement period

The roll forward of the capital base from 20 August 2010 is summarised in Table 7.

The resulting end of year asset value is the opening capital base for the following year.

In the period 20 August 2010 to 31 December 2010:

(a) conforming capital expenditure made during the period is added to the opening capital at the beginning of the period; and

(b) depreciation during the period is subtracted.

In the each year from 1 January 2011 to 31 December 2014:

(a) conforming capital expenditure made during the year is added to the opening capital at the beginning of the year; and

(b) depreciation during the year is subtracted.

Table 7: Roll forward of capital base

	2010 $ million	2011 $ million	2012 $ million	2013 $ million	2014 $ million
Opening capital base					
Pipeline and laterals	366.958	364.428	357.617	350.806	344.020
Main line valve and scraper stations	7.013	6.937	6.729	6.521	6.312
Compressor stations	44.626	43.822	41.134	38.543	36.245
Receipt and delivery point facilities	2.028	1.988	1.876	1.762	1.781
SCADA and communications	2.133	2.138	2.304	2.708	2.727
Cathodic protection	1.655	1.611	1.404	1.106	0.806
Maintenance bases and depots	6.159	6.126	5.948	5.768	6.909
Other (depreciable) assets	1.863	1.729	1.044	0.155	-0.245
Non-depreciable assets	3.823	3.823	3.823	3.823	3.823
	436.258	**432.602**	**421.878**	**411.191**	**402.379**
Capital expenditure					
Pipeline and laterals	-0.030	0.000	0.000	0.026	0.000
Main line valve and scraper stations	0.000	0.000	0.000	0.000	0.000
Compressor stations	0.158	0.047	0.259	0.580	0.909
Receipt and delivery point facilities	0.000	0.000	0.000	0.136	0.174
SCADA and communications	0.067	0.364	0.727	0.473	0.866
Cathodic protection	0.000	0.000	0.000	0.000	0.000
Maintenance bases and depots	0.033	0.000	0.000	1.320	0.091
Other (depreciable) assets	0.016	0.023	0.026	0.567	0.951
Non-depreciable assets	0.000	0.000	0.000	0.000	0.000
	0.244	**0.435**	**1.012**	**3.101**	**2.991**
Depreciation					
Pipeline and laterals	2.500	6.811	6.811	6.811	6.811
Main line valve and scraper stations	0.076	0.208	0.208	0.208	0.208
Compressor stations	0.963	2.735	2.850	2.877	2.906
Receipt and delivery point facilities	0.040	0.112	0.114	0.116	0.118
SCADA and communications	0.062	0.198	0.324	0.453	0.485
Cathodic protection	0.044	0.207	0.297	0.300	0.302
Maintenance bases and depots	0.065	0.179	0.179	0.180	0.180
Other (depreciable) assets	0.150	0.709	0.915	0.967	1.018
	3.901	**11.159**	**11.699**	**11.913**	**12.029**
End of year value					
Pipeline and laterals	364.428	357.617	350.806	344.020	337.209
Main line valve and scraper stations	6.937	6.729	6.521	6.312	6.104
Compressor stations	43.822	41.134	38.543	36.245	34.248
Receipt and delivery point facilities	1.988	1.876	1.762	1.781	1.837
SCADA and communications	2.138	2.304	2.708	2.727	3.108
Cathodic protection	1.611	1.404	1.106	0.806	0.504
Maintenance bases and depots	6.126	5.948	5.768	6.909	6.820
Other (depreciable) assets	1.729	1.044	0.155	-0.245	-0.312
Non-depreciable assets	3.823	3.823	3.823	3.823	3.823
	432.602	**421.878**	**411.191**	**402.379**	**393.341**

During the period 20 August 2010 to 31 December 2014:

(a) no amounts were added to the capital base under rules 82, 84 or 86;

(b) no redundant assets were identified or removed from the capital base; and

(c) there were no asset disposals requiring a reduction in the capital base.

6.6 Nominal total revenue determination and cost escalation

Rule 87(4), in effect, imposes a requirement that the total revenue from which reference tariffs are determined is to be in nominal terms.

The forecast of capital expenditure used rolling forward the capital base from the commencement of the access arrangement period (and the forecast of operating expenditure used in total revenue determination) must, therefore, be in nominal terms. They must be in "dollars of the day", and not expressed in terms of the prices prevailing at some earlier time.

The forecasts of capital expenditure which GGT has used were prepared early in 2014. They were prepared using the prices for materials and services prevailing at that time. These forecasts have been re-expressed in nominal terms by applying an expected rate of price increase – expected inflation – for the period 2015 to 2019.

The ERA's December 2013 *Rate of Return Guidelines* propose that expected inflation be estimated from the yields on nominal and indexed Commonwealth Government bonds using the Fisher equation. The estimate obtained in this way is less than 2%.

In its May 2014 *Statement on Monetary Policy*, the Reserve Bank of Australia advised that underlying inflation is currently around 2.75% and is expected to be in the range 2% to 3% during 2015 and 2016.

An estimate of inflation of less than 2%, made using a simple mechanical rule, the Fisher equation, is not a credible estimate for the period 2015 to 2019 when the central bank is indicating that inflation is currently around 2.75% and is expected to be in the range 2% to 3% in the future.[19]

The Reserve Bank comments that the national outlook for inflation continues to reflect the influence of two opposing effects:

(a) excess capacity in product and labour markets, which is likely to contain profit margins and lead to moderate growth in labour costs; and

[19] The Fisher equation is $\pi^e = (1 + r_n)/(1 + r_i) - 1$, where r_n is a measure of the nominal interest rate (usually the yield on longer term government bonds), and r_i is a measure of the real interest rate (the yield on indexed bonds). That the difference between r_n and r_i is simply expected inflation, π^e, is not clear. r_i is endogenously determined. r_n will usually be a function of, among other things, macroeconomic policy settings, in particular the extent to which the central bank adopts an interest rate rule, money supply targeting, money market operations and, in an open economy, the extent to which policy making has regard for the level of the exchange rate.

(b) the increase in import prices coming from depreciation of the exchange rate since early 2013.

A similar view lies behind forecasts of inflation for Western Australia are provided in the State Government's Budget Paper No. 3, which was appended to the budget presented to Parliament on 8 May 2014. These forecasts are shown in Table 8.

Table 8: Economic forecasts: Western Australia

	2014-15	2015-16	2016-17	2017-18
Annual growth	%	%	%	%
Consumer Price Index	2.75%	2.5%	2.5%	2.5%
Wage Price Index	3.25%	3.5%	3.5%	3.75%

Source: Government of Western Australia, *2014-15 Budget, Economic and Fiscal Outlook*, Budget Paper No. 3, page 18.

Budget Paper No. 3 advises that wage growth is now subdued relative to what it had been in 2012 and 2013, but is expected to strengthen over the period 2015 to 2018 consistent with a steady improvement in Western Australian labour market conditions, and in the domestic economic outlook.

GGT's forecast capital and operating expenditures are largely forecasts of the costs of services provided by external suppliers. The proportions of labour and materials in these costs are not known to GGT. For the purpose of preparing the nominal forecasts required for total revenue determination, GGT has assumed inflation of 3.0%, which is, approximately, the mid-point between the Budget Paper No. 3 forecast of the increase in the Consumer Price Index and the Wage Price Index.

Assuming inflation at 3.0% may lead to forecasts which are lower than the costs which GGT subsequently incurs to the extent that wage growth accelerates again. GGT notes that the largest of the external suppliers of services to the Covered Pipeline are APA Group entities which provide the personnel – labour – for pipeline operation and maintenance.

6.7 Forecast capital expenditure

Forecast capital expenditure on the Covered Pipeline during the period 1 January 2015 to 31 December 2019 is summarised in Table 9.

Table 9: Capital expenditure by asset class: 2015-2019

	2015	2016	2017	2018	2019
	$ million	$ million	$ million	$ million	$ million
Pipeline and laterals	3.387	2.000	0.313	0.000	0.255
Main line valve and scraper stations	0.000	0.700	0.000	0.000	0.000
Compressor stations	1.070	0.899	0.000	0.242	0.344
Receipt and delivery point facilities	0.408	0.000	0.721	0.421	0.000
SCADA and communications	0.567	0.498	0.216	0.050	0.051
Cathodic protection	0.102	0.036	0.094	0.028	0.029
Maintenance bases and depots	0.658	0.000	0.000	0.000	0.000
Other assets	0.593	0.105	0.084	0.062	0.064
	6.784	**4.238**	**1.428**	**0.803**	**0.743**

The forecasts in Table 9 are forecasts of the amounts expected to be spent (they are in "dollars of the day"). Expenditure estimates made using 2014 labour and materials prices have been escalated at expected inflation of 3.0%.

As can be seen from Table 9, a significant proportion of the forecast capital expenditure is in the asset class "Pipeline and laterals". The majority of this expenditure (over 90%) is for:

(a) planned in-line inspection (pigging) of the GGP mainline, the Newman Lateral, the Apache-GGP interconnect pipeline, and the DBNGP-GGP interconnect pipeline; and

(b) associated verification "dig-ups" to confirm pipeline integrity.

In-line inspection is the only way to adequately assess the integrity of the buried pipeline. Integrity assessment is a requirement of Pipeline Licence PL24, the instrument which licences the GGP mainline, the Newman Lateral, the Apache-GGP interconnect pipeline, and some 440 metres of the DBNGP-GGP interconnect pipeline (the remaining 1.46 kilometres of that pipeline coming within the scope of PL40, the pipeline licence for the Dampier to Bunbury Natural Gas Pipeline).

The GGP was last inspected in 2004-5. The pipe was found to be in good condition, and the technical regulator, the Western Australian Department of Mines and Petroleum, subsequently agreed to a ten-year inspection cycle. In-line inspection of the pipeline is therefore scheduled for 2015.

The Apache-GGP and DBPNG-GGP interconnect pipelines were not constructed to allow in-line inspection. The forecast integrity assessment expenditure therefore includes expenditure on the installation of pig launchers and receivers on each of the interconnect pipelines. This expenditure is in the asset class "Main line valve and scraper stations", and is 100% of the forecast expenditure in that class for the access arrangement period.

Forecast expenditure on compressor stations is for a number of smaller projects. The largest of these are:

(a) major overhaul of Paraburdoo compressor unit 1 (about 20% of expenditure in asset class "Compressor stations"); and

(b) hazardous area upgrades and inspections to meet the requirements of AS60079 (about 35% of forecast costs in the asset class "Compressor stations").

The remaining 45% of forecast expenditure on Compressor Stations is spread across 10 projects, none of which exceeds $250,000.

The majority of forecast expenditure on assets in the class "Receipt and delivery point facilities" (about 70%) relates to the replacement of flow computers at the following sites:

(a) Paraburdoo;

(b) Ilgarari;

(c) Wiluna;

(d) Jeedamya scraper station;

(e) Leonora; and

(f) Murrin Lateral inlet.

The existing flow computers are now obsolete, and are no longer supported by the manufacturer. Although they are still operable, obtaining spares and completing repairs are becoming increasingly difficult. The flow computers are to be replaced before there is a significant failure.

The other significant item in this asset class about (25%) is forecast expenditure for the installation of two gas chromatographs, capable of detecting up to C9 hydrocarbons, to allow the calculation of hydrocarbon dewpoint.

GGP has forecast expenditure in the asset class "SCADA and communications" for the roll out of a standard SCADA satellite solution to all sites on the Covered Pipeline. Existing equipment is to be replaced, and a common encryption standard is to be enforced for all SCADA communications. The current satellite communication platform is ageing and is vulnerable to failure. Moving to the APA national satellite standard will resolve these issues and provide a more secure communication platform for the GGP.

A further significant project in the asset class "SCADA and communications" the replacement of the 15 remaining Modicon Quantum station remote terminal units (RTUs) in operation on the GGP (about 25% of forecast costs in the SCADA and

communications asset class). These units are outdated and their programming language is no longer compatible with other GGP equipment.

Forecast expenditure in the asset class "Cathodic protection" is largely for the replacement and upgrading of surge diverters and power supplies.

The principal item of forecast expenditure on assets in the class "Maintenance bases and depots" is for the rebuilding of Karratha maintenance base. Work on the base building during 2014 identified substantial structural damage resulting from "settling". The Karratha base is essential to field operations at the northern end of the GGP.

Further information on these expenditures, and the reasons why GGT considers them to be conforming capital expenditures and therefore able to be taken into account in establishing the project capital base for the Covered Pipeline, are set out in the business cases included in Attachment 7 to the Supporting Information (Forecast conforming capital expenditure: 2015-2019).

6.8 Depreciation 2015-2019

Depreciation during the period 2015-2019 is shown in Table 10.

Table 10: Depreciation 2015-2019

	2015	2016	2017	2018	2019
	$ million	$ million	$ million	$ million	$ million
Pipeline and laterals	6.811	6.811	6.860	6.888	6.893
Main line valve and scraper stations	0.207	0.207	0.207	0.221	0.221
Compressor stations	2.622	2.680	2.716	2.746	2.746
Receipt and delivery point facilities	0.109	0.120	0.133	0.133	0.157
SCADA and communications	0.169	0.305	0.341	0.370	0.371
Cathodic protection	0.119	0.119	0.126	0.128	0.133
Maintenance bases and depots	0.178	0.210	0.223	0.223	0.223
Other assets	0.133	0.265	0.301	0.282	0.259
	10.349	**10.716**	**10.906**	**10.991**	**11.003**

The depreciation in Table 10 comprises:

(a) depreciation on the initial capital base, and on the assets created by the capital expenditures which were added to that initial capital base during the period from 2000 to 2014; and

(b) depreciation on the assets expected to be created by the capital expenditure forecast to be made during the period 2015 to 2019.

Each of these two components of depreciation has been calculated using the straight line method.

A demonstration of the derivation of the depreciation on the assets expected to be created by the capital expenditure forecast to be made during the period 2015 to 2019 is provided in Table 11.

Table 11: Derivation of forecast depreciation

Asset class	Asset life		CAPEX	Depreciation					Asset value
				2015	2016	2017	2018	2019	1 January 2020
[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]
2015 CAPEX									
Pipeline and laterals	70 years	$m	3.387		0.048	0.048	0.048	0.048	3.193
Main line valve and scraper stations	50 years	$m	0.000		0.000	0.000	0.000	0.000	0.000
Compressor stations	30 years	$m	1.070		0.036	0.036	0.036	0.036	0.927
Receipt and delivery point facilities	30 years	$m	0.408		0.014	0.014	0.014	0.014	0.353
SCADA and communications	15 years	$m	0.567		0.038	0.038	0.038	0.038	0.416
Cathodic protection	15 years	$m	0.102		0.007	0.007	0.007	0.007	0.075
Maintenance bases and depots	50 years	$m	0.658		0.013	0.013	0.013	0.013	0.606
Other depreciable assets	10 years	$m	0.593		0.059	0.059	0.059	0.059	0.356
2016 CAPEX									
Pipeline and laterals	70 years	$m	2.000			0.029	0.029	0.029	1.914
Main line valve and scraper stations	50 years	$m	0.700			0.014	0.014	0.014	0.658
Compressor stations	30 years	$m	0.899			0.030	0.030	0.030	0.809
Receipt and delivery point facilities	30 years	$m	0.000			0.000	0.000	0.000	0.000
SCADA and communications	15 years	$m	0.498			0.033	0.033	0.033	0.399
Cathodic protection	15 years	$m	0.036			0.002	0.002	0.002	0.029
Maintenance bases and depots	50 years	$m	0.000			0.000	0.000	0.000	0.000
Other depreciable assets	10 years	$m	0.105			0.011	0.011	0.011	0.074
Depreciation: 2017 CAPEX									
Pipeline and laterals	70 years	$m	0.313				0.004	0.004	0.304
Main line valve and scraper stations	50 years	$m	0.000				0.000	0.000	0.000
Compressor stations	30 years	$m	0.000				0.000	0.000	0.000
Receipt and delivery point facilities	30 years	$m	0.721				0.024	0.024	0.673
SCADA and communications	15 years	$m	0.216				0.014	0.014	0.188
Cathodic protection	15 years	$m	0.094				0.006	0.006	0.081
Maintenance bases and depots	50 years	$m	0.000				0.000	0.000	0.000
Other depreciable assets	10 years	$m	0.084				0.008	0.008	0.067
Depreciation: 2018 CAPEX									
Pipeline and laterals	70 years	$m	0.000					0.000	0.000
Main line valve and scraper stations	50 years	$m	0.000					0.000	0.000
Compressor stations	30 years	$m	0.242					0.008	0.234
Receipt and delivery point facilities	30 years	$m	0.421					0.014	0.407
SCADA and communications	15 years	$m	0.050					0.003	0.046
Cathodic protection	15 years	$m	0.028					0.002	0.027
Maintenance bases and depots	50 years	$m	0.000					0.000	0.000
Other depreciable assets	10 years	$m	0.062					0.006	0.056
Depreciation: 2019 CAPEX									
Pipeline and laterals	70 years	$m	0.255						0.255
Main line valve and scraper stations	50 years	$m	0.000						0.000
Compressor stations	30 years	$m	0.344						0.344
Receipt and delivery point facilities	30 years	$m	0.000						0.000
SCADA and communications	15 years	$m	0.051						0.051
Cathodic protection	15 years	$m	0.029						0.029
Maintenance bases and depots	50 years	$m	0.000						0.000
Other depreciable assets	10 years	$m	0.064						0.064
CAPEX: Non-depreciable assets: 2015-2019		$m	0.000						0.000
			13.997	**0.000**	**0.215**	**0.333**	**0.391**	**0.424**	**12.634**

As explained in section 5 above, depreciation is calculated for each of eight asset classes. For the assets in each class, depreciation is calculated by dividing the value of the assets in the class, at the time of their inclusion in the capital base, by the expected economic life of the assets in the class.

Table 11 sets out depreciation calculated from the forecast conforming capital expenditure in each year of the period 2015 to 2019. The conforming capital expenditure for each asset class, in each year, is shown in column [3]. The capital expenditure is added to the capital base at the end of the year in which it is forecast to be made, and depreciation commences in the following year. For example, forecast expenditure of $3.387 million on Pipeline and laterals in 2015 is added to the capital base at the end of that year, and is depreciated from the beginning of 2016. The depreciation is the value of the assets included in the capital base ($3.387 million) divided by the expected economic life of assets in the class Pipeline and laterals (70 years, as shown in column [2]. The depreciation in 2016, $0.048 million, is shown in column [5]. Depreciation in the subsequent years of the access arrangement period is shown in columns [6] to [8]. Column [9] shows the residual or "written down" value of the asset class at the end of the access arrangement period. The entry in column [9], for expenditure on Pipeline and laterals in 2015, $3.193 million, is the difference between the value added to the capital base, $3.387 million, and the accumulated depreciation over the period 2016 to 2019 ($0.194 million, the sum of the entries in columns [5] to [8]).

Since the actual capital expenditure for the period 2010 to 2014 was less than forecast, an adjustment has been made for "over-depreciation". This adjustment has been calculated, and applied, in the same way in which the ERA calculated and applied the adjustment for over-depreciation at the end of 2010.

The components of the over-depreciation adjustment are shown in Table 12.

Table 12: Over-depreciation adjustment 2014

	$ million
Pipeline and laterals	0.083
Main line valve and scraper stations	0.005
Compressor stations	0.318
Receipt and delivery point facilities	0.021
SCADA and communications	0.012
Cathodic protection	0.631
Maintenance bases and depots	0.002
Other assets	2.138
	3.211

The over-depreciation adjustment shown in Table 12 is added to the opening capital base at 1 January 2015, and is subtracted from the total revenue for that year.

6.9 Projected capital base

The projection of the capital base forward from 1 January 2015 is summarised in Table 13.

Table 13: Projected capital base 2015-2019

	2015 $ million	2016 $ million	2017 $ million	2018 $ million	2019 $ million
Opening capital base					
Pipeline and laterals	337.292	333.868	329.057	322.509	315.621
Main line valve and scraper stations	6.110	5.903	6.396	6.189	5.968
Compressor stations	34.565	33.013	31.232	28.516	26.012
Receipt and delivery point facilities	1.859	2.157	2.037	2.625	2.913
SCADA and communications	3.120	3.518	3.711	3.586	3.265
Cathodic protection	1.135	1.118	1.036	1.004	0.904
Maintenance bases and depots	6.822	7.302	7.092	6.870	6.647
Other (depreciable) assets	1.826	2.286	2.126	1.909	1.689
Non-depreciable assets	3.823	3.823	3.823	3.823	3.823
	396.552	**392.988**	**386.510**	**377.031**	**366.843**
Capital expenditure					
Pipeline and laterals	3.387	2.000	0.313	0.000	0.255
Main line valve and scraper stations	0.000	0.700	0.000	0.000	0.000
Compressor stations	1.070	0.899	0.000	0.242	0.344
Receipt and delivery point facilities	0.408	0.000	0.721	0.421	0.000
SCADA and communications	0.567	0.498	0.216	0.050	0.051
Cathodic protection	0.102	0.036	0.094	0.028	0.029
Maintenance bases and depots	0.658	0.000	0.000	0.000	0.000
Other (depreciable) assets	0.593	0.105	0.084	0.062	0.064
Non-depreciable assets	0.000	0.000	0.000	0.000	0.000
	6.784	**4.238**	**1.428**	**0.803**	**0.743**
Depreciation					
Pipeline and laterals	6.811	6.811	6.860	6.888	6.893
Main line valve and scraper stations	0.207	0.207	0.207	0.221	0.221
Compressor stations	2.622	2.680	2.716	2.746	2.746
Receipt and delivery point facilities	0.109	0.120	0.133	0.133	0.157
SCADA and communications	0.169	0.305	0.341	0.370	0.371
Cathodic protection	0.119	0.119	0.126	0.128	0.133
Maintenance bases and depots	0.178	0.210	0.223	0.223	0.223
Other (depreciable) assets	0.133	0.265	0.301	0.282	0.259
Non-depreciable assets	6.811	6.811	6.860	6.888	6.893
	10.349	**10.716**	**10.906**	**10.991**	**11.003**
End of year asset value					
Pipeline and laterals	333.868	329.057	322.509	315.621	308.983
Main line valve and scraper stations	5.903	6.396	6.189	5.968	5.748
Compressor stations	33.013	31.232	28.516	26.012	23.611
Receipt and delivery point facilities	2.157	2.037	2.625	2.913	2.755
SCADA and communications	3.518	3.711	3.586	3.265	2.945
Cathodic protection	1.118	1.036	1.004	0.904	0.800
Maintenance bases and depots	7.302	7.092	6.870	6.647	6.424
Other (depreciable) assets	2.286	2.126	1.909	1.689	1.494
Non-depreciable assets	3.823	3.823	3.823	3.823	3.823
	392.988	**386.510**	**377.031**	**366.843**	**356.584**

7 Rate of return

The return on the projected capital base included in the total revenue is to be determined as the product of a rate of return – the allowed rate of return – and the projected capital base at the beginning of each regulatory year of an access arrangement period (rule 87(1)).

The way in which GGT proposes to determine the allowed rate of return, guided by the ERA's Rate of Return Guidelines, is set out in this section of the Supporting Information.

This section also indicates where, in determining the proposed allowed rate of return, GGT has departed from the Rate of Return Guidelines, and sets out the reasons for its departure from those guidelines.[20]

GGT has used the Sharpe-Lintner Capital Asset Pricing Model (Sharpe-Lintner CAPM) to estimate a return on equity for the Covered Pipeline of 12.28%. The rate of return on debt has been estimated as the sum of the risk free rate plus debt risk premium plus allowances for debt raising and hedging costs. GGT's estimate, 7.89%, has been obtained using a trailing average, rather than as an on-the-day estimate, for the reasons given later in the Supporting Information. With gearing of 60% for the benchmark efficient entity of rule 87, GGT's proposed allowed rate of return (expressed as a nominal vanilla weighted average of returns on equity and debt) is 9.64%.

In this section of the Supporting Information, GGT:

(a) notes the rules governing rate of return, and their requirement for the Rate of Return Guidelines;

(b) sets out the reasons for adopting the gearing and credit rating for the benchmark efficient entity of the Guidelines;

(c) discusses estimation of the risk free rate of return and explains why an estimate of that rate should be made using yields on Commonwealth Government bonds with terms to maturity of 10 years (and not with terms to maturity of five years);

(e) explains its approach to estimation of the return on equity and, in particular, to estimation for an equity beta for the Covered Pipeline which does not rely on an assumed similarity with those Australian utility businesses which have traded shares and for which betas can be estimated using share price and dividend data; and

(f) sets out estimation of the rate of return on debt using an on-the-day approach, shows that that rate of return does not allow the recovery of efficiently incurred

[20] These are the reasons which are to be included in the GGP Access Arrangement Information in accordance with the requirement of rule 72(1)(g).

financing costs, and proposes an estimate made using a trailing average approach.

7.1 Rules governing the rate of return

The allowed rate of return is to be determined such that it achieves the allowed rate of return objective (rule 87(2)). The objective is stated in rule 87(3):

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

The allowed rate of return is to be determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in rule 87A (rule 87(4)(b)). That is, the allowed rate of return for a regulatory year is to be a simple weighted average of the return on equity for the access arrangement period in which the regulatory year occurs, and the return on debt for that regulatory year.

Rule 87(5) requires that, in determining the allowed rate of return, regard be had to:

(a) relevant estimation methods, financial models, market data and other evidence;

(b) the desirability of an approach that leads to the consistent application of estimates of financial parameters relevant and common to estimation of the return on equity and the return on debt; and

(c) interrelationships between estimates of financial parameters relevant to estimation of the return on equity and the return on debt.

The return on equity for the access arrangement period is to be estimated such that it contributes to achievement of the allowed rate of return objective (rule 87(6)). In estimating a return on equity which contributes to achievement of the objective, regard must be had to prevailing conditions in the market for equity (rule 87(7)).

The return on debt for a regulatory year must, similarly, be estimated such that it contributes to the allowed rate of return objective (rule 87(8)). However, there is flexibility in the approach which can be taken. The return on debt may be estimated using a method which results in either:

(a) the return on debt for each regulatory year in the access arrangement period being the same (rule 87(9)(a)); or

(b) the return on debt (and, in consequence, the allowed rate of return) being, or potentially being, different for different regulatory years in an access arrangement period (rule 87(9)(b)).

Subject to the resulting estimate contributing to achievement of the allowed rate of return objective, the method used to estimate the rate of return on debt may result in a return which reflects:

(a) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the time the ERA's decision on the proposed access arrangement revisions is made (rule 87(10)(a));

(b) the average return that would have been required by debt investors in the benchmark efficient entity if it raised debt over a historical period prior to the regulatory year in which the proposed access arrangement revisions are to commence (rule 87(10)(b)); or

(c) a combination of the returns referred to in (a) and (b) (rule 87(10)(c)).

In estimating the return on debt, regard must be had to the following factors:

(a) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective rule 87(11)(a));

(b) the interrelationship between the return on equity and the return on debt (rule 87(11)(b));

(c) the incentives that the return on debt may provide in relation to capital expenditure over the access arrangement period (rule 87(11)(c)); and

(d) any impacts on the benchmark efficient entity of the allowed rate of return objective that could arise as a result of changing the method that is used to estimate the return on debt from one access arrangement period to the next (rule 87(11)(d)).

If the return on debt is estimated using a method which results in that return, and the allowed rate of return, being, or potentially being, different for each regulatory year of an access arrangement period, then the service provider's total revenue must be changed through the automatic application of a formula that is specified in the ERA's decision on the proposed access arrangement revisions (rule 87(12)).

The methods to be used in determining the allowed rate of return, and the estimation methods, financial models, market data and other evidence to be taken into account in estimating the return on equity, the return on debt, and the value of imputation credits, are to be set out in rate of return guidelines to be made and published by the ERA in accordance with rule 87(13). The guidelines must also describe how these methods are proposed to result in the determination of a return on equity and a return on debt in a way that is consistent with the allowed rate of return objective.

The rate of return guidelines are not mandatory, and do not bind the ERA or anyone else (rule 87(18)). However, reasons must be given for any departure from the guidelines. If a service provider proposes to depart from the methods set out in the rate of return guidelines, the access arrangement information for its access arrangement revision proposal must advise of the departure and the reasons for that departure (rule 72(1)(g)).

7.2 ERA Rate of Return Guidelines

Rate of return guidelines were made and published by the ERA on 16 December 2013 (Rate of Return Guidelines). The Rate of Return Guidelines set out methods for estimating the return on equity and the return on debt which should guide determination of the allowed rate of return. They also establish:

(a) the proportions of equity and debt in the total financing of the benchmark efficient entity, which are to be used to weight the returns on equity and debt for the purpose of determining a weighted average on a nominal vanilla basis;

(b) the value which is to be attributed to imputation credits for the purpose of making the estimate referred to in rule 87A; and

(c) an approach to be taken to estimation of the expected rate of inflation which may be used as an input to the modelling of total revenue in nominal terms (as now required by rule 87).

In addition to making and publishing guidelines, the ERA also issued, on 16 December 2013, an Explanatory Statement for the Rate of Return Guidelines (Explanatory Statement).

7.3 Economic principles

In the Rate of Return Guidelines, the ERA advises that rate of return methods should be driven by economic principles. They should have strong theoretical foundations, and should be informed by empirical analysis (Rate of Return Guidelines, paragraph 37).

That the methods are to be driven by economic principles is to be understood as meaning that observations are to be made in accordance with established scientific methods, that established theories are to be used, and that recognised empirical methods are to be applied in estimating the parameters required for the application of those theories (Explanatory Statement, Appendix 1, paragraph 13).

Paragraph 19 of Appendix 1 to the Explanatory Statement further explains: good empirical methods are desirable but, alone, they are insufficient. Empirical analysis, uninformed by relevant theory, risks being little more than “data mining”.

GGT is of the view that economic principles, particularly principles with strong empirical support, can provide guidance where the NGL and the NGR are silent, and where an exercise of judgement is required. When economic principles are applied, as is very likely to be the case in determination of the allowed rate of return, they should be applied in ways which are consistent with those theories. Departure from the underlying theories, or from the empirical support, would mean that rate of return determination was inherently arbitrary, and that there was no reason to expect that the resulting rate of return could achieve the allowed rate of return objective.

7.4 Gearing

The allowed rate of return of rule 87 is to be the weighted average of the return on equity and the return on debt determined on a nominal vanilla basis (rules 87(4)(a) and (b)). In a weighted average determined on a nominal vanilla basis, the weight to be given to the return on equity should be the proportion of equity in the total capital of the benchmark efficient entity (which is assumed to be financed by equity and debt). The weight to be given to the return on debt – the gearing – should be the proportion of debt in the total capital of the benchmark efficient entity.

Paragraph 64 of the Rate of Return Guidelines advises that the gearing should be determined as the average gearing of a sample of Australian utility businesses with similar risk to the service provider in its provision of reference services.

The Rate of Return Guidelines propose that businesses in the sample have the following characteristics:

(a) they are to be network service providers in either the Australian electricity industry, or in the Australian gas industry (because they have similar risk);

(b) they are to be entities listed on the Australian Stock Exchange so that an estimate can be made of the market value of equity; and

(c) data must be available on the value of debt.

When these characteristics are used to select a sample of utility businesses, the data for the period 2008 to 2012 indicates a gearing of 60% (Rate of Return Guidelines, paragraph 67, and Explanatory Statement, section 5).

Paragraph 67 of the Rate of Return Guidelines advises that a gearing of 60% will meet the allowed rate of return objective.

Characteristics (b) and (c) are unexceptional: they ensure that data required for estimation of the gearing are available.

Characteristic (a) is problematic. Before the gearing can be established, a sample of utility businesses with similar risk to the service provider in its provision of reference services must be identified. That, in turn, requires a method for assessing similarity of risk. The Rate of Return Guidelines offer little assistance with a method of risk assessment, or with its application. Similarity is assumed. However, as GGT notes later in this Supporting Information, when risk is measured broadly, as systematic risk, there is no clear evidence that Australian electricity network service providers and Australian gas pipeline service providers have similar risk. Nor is there evidence to support the view that Australian pipeline service providers have similar risk.

Nevertheless, GGT recognises that the listed Australian electricity network and gas pipeline service providers have broadly similar capital structures. GGT has therefore assumed that the gearing of the benchmark efficient entity is 60%, and has used this gearing to calculate the nominal vanilla weighted average of returns on equity and debt which is to be the allowed rate of return for the GGP Access Arrangement

revision proposal. As will be explained later in this Supporting Information, GGT's estimate of an equity beta for use with the Sharpe-Lintner CAPM has been made using, and is consistent with, a gearing of 60%.

7.5 Credit rating

Determination of a rate of return for a benchmark efficient entity with degree of risk similar to that of the service provider in its provision of references services requires a measure of credit risk. The Rate of Return Guidelines propose that credit risk be measured using a credit rating issued by an international ratings agency. The credit risk of the benchmark efficient entity is, then, to be established from these credit ratings for a sample of Australian utilities (Rate of Return Guidelines, paragraph 98). This sample is to comprise Australian gas or electricity network service providers drawn from the Standard and Poor's industry report card (Rate of Return Guidelines, paragraph 99).

Again, the issue of assessing similarity of risk arises in choosing a relevant sample of utilities, but the Rate of Return Guidelines provide little guidance on how the issue might be addressed.

The ERA's analysis indicates that, for the purpose of the guidelines, the benchmark credit rating is the BBB-/BBB/BBB+ rating band (Rate of Return Guidelines, paragraph 100).

7.6 Estimating the risk free rate of return

The allowed rate of return for a regulatory year is to be a weighted average of the return on equity for the access arrangement period in which the regulatory year occurs, and the return on debt for that regulatory year.

Each of the methods for estimating the return on equity and the return on debt set out in the Rate of Return Guidelines requires, as an input to estimation, an estimate of the risk free rate of return.

The Rate of Return Guidelines advise that the risk free rate may be estimated as either a nominal rate of return (which compensates investors for changes in purchasing power caused by inflation), or as a real rate of return (from which the expected effect of inflation has been removed). Since the allowed rate of return is to be determined on a nominal vanilla basis, the estimate of the risk free rate should be a nominal rate of return (Rate of Return Guidelines, paragraph 91).

The risk free rate of return is the rate of return on a financial asset which is without risk. It is the rate of return on a financial asset which provides an investor with the same return in each contingent state.

To estimate the risk free rate of return, a proxy for this financial asset which is without risk – the risk free asset – must be found from among the traded financial assets for which returns can be observed. This proxy is to be Commonwealth Government

bonds, for which observed yields are reported daily by the Reserve Bank of Australia (Rate of Return Guidelines, paragraph 92).

The term to maturity of the Commonwealth Government bonds to be used as the proxy for the risk free asset is to be five years (Rate of Return Guidelines, paragraph 94).

Since it is not common to observe, at a given time, yields on bonds with a term to maturity of exactly five years, yields must be observed for bonds with terms to maturity of around five years, and those yields are to be adjusted to match the required term (five years) using linear interpolation (Rate of Return Guidelines, paragraph 93).

To remove the effects of "noise" from the estimate of the risk free rate of return, yields are to be obtained for Commonwealth Government bonds with the required term to maturity during a period of 40 trading days immediately prior to the commencement of the access arrangement period for which the allowed rate of return is being determined. The risk free rate of return is to be estimated as an average of these yields during the 40 trading days (Rate of Return Guidelines, paragraph 95).

The Explanatory Statement sets out the reasons for choosing Commonwealth Government bonds with terms to maturity of five years as the proxy for the risk free asset.

The present value principle, the Explanatory Statement advises, requires that the term to maturity of the proxy for the risk free asset be equal to the length of the access arrangement period for which the allowed rate of return is being determined. Using a proxy with a term to maturity equal to the length of the access arrangement period should lead to reference tariffs which neither over-compensate nor under-compensate the service provider for the costs expected to be incurred in providing reference services during that period (Explanatory Statement, paragraph 444).

Appendix 2 to the Explanatory Statement describes the present value principle, and explains why that principle requires that the term to maturity of the proxy for the risk free asset be equal to the length of the access arrangement period. This explanation is supported, the Explanatory Statement advises, by the conclusions from a series of studies, some published in academic journals, and others undertaken for regulators, by Victoria University Associate Professor Martin Lally, and by University of Melbourne Professor Kevin Davis.

7.6.1 The present value principle

The reference tariffs which are to apply during an access arrangement period are usually set as the tariffs which equate the present value of the forecast revenue from the provision of reference services with the present value of the efficiently incurred costs of providing those services. These present value calculations can be carried out using any discount rate.

However, if the discount rate used is less than the rate of return (which may be a weighted average of returns on equity and debt) used to calculate the financing costs included in the efficiently incurred costs of providing services, the present value of that

part of the forecast revenue which recovers those financing costs will exceed the present value of the investment in the assets used to provide reference services. The tariffs calculated using that discount rate will over-recover the investment in the assets used to provide services.

If the discount rate used is greater than the rate of return used to calculate the financing costs, the present value of that part of the forecast revenue which recovers those financing costs will be less than the present value of the investment in the assets used to provide reference services. The tariffs calculated using that discount rate will under-recover the investment in the assets used to provide services.

Only when the discount rate used in the present value calculations is equal to the rate of return used to calculate the financing costs included in the efficient costs of providing reference services will the present value of that part of the forecast revenue which recovers financing costs be equal to the present value of the investment in the assets used to provide the services.

Only when the discount rate used in the present value calculations is equal to the rate of return used to calculate the financing costs included in the efficient costs of providing reference services will the tariff calculated using that discount rate recover the investment in the assets used to provide those services. This is the "present value principle" to which the Explanatory Statement refers.

The present value principle will be satisfied for any rate of return, provided the rate of return used in discounting cash flows for reference tariff calculation is the same as the rate of return used in determining the return included in total revenue. The present value principle does not impose any constraint on the way in which the rate of return is estimated, or on the "internal structure" of that rate of return. In particular, the present value principle does not require that the term to maturity of a proxy for the risk free asset which might be used in estimating the rate of return be equal to the length of the access arrangement period.

Furthermore, as we explain in the paragraphs which follow, the studies by Associate Professor Lally, and by Professor Davis, to which the Explanatory Statement refers, do not provide support for a view that the term to maturity of the proxy for the risk free asset should be equal to the length of the access arrangement period so that the present value principle is satisfied.

7.6.2 Studies by Associate Professor Lally

Appendix 2 to the Explanatory Statement discusses, at some length, papers published by Associate Professor Lally in 2004 and 2007, and a report he prepared for the Queensland Competition Authority in 2010.[21]

In the first paragraph of his 2007 paper (which further develops the argument of his 2004 paper), Associate Professor Lally advises:

[21] Martin Lally (2004), "Regulation and the Choice of the Risk Free Rate", Accounting Research Journal, 17(1): pages 18-23; Martin Lally (2007), "Regulation and the Term of the Risk Free Rate: Implications of Corporate Debt", Accounting Research Journal, 20(2): pages 73-80; and Martin Lally, *The Appropriate Term for the Risk Free Rate and the Debt Margin*, 27 April 2010.

In regulating the output prices of firms, the usual process involves periodic reassessment of prices in the light of prevailing costs, and the cost of capital is generally a significant component of these costs. In turn, the risk free rate is a significant component of the cost of capital. However, at any given point in time, there is a range of risk free rates corresponding to the range of maturity dates for government bonds, and this gives rise to the question of which term should be used.[22]

The second paragraph of the paper continues:

In assessing the appropriate action by the regulator, the fundamental principle to be satisfied is that the present value of the net cash flows to equity holders should equal their initial investment (Marshall et al, 1981). If this principle is not satisfied, then equity investors are either over or under compensated by the regulator.[23]

At the end of this second paragraph, Associate Professor Lally sets out his purpose:

Accordingly, this paper seeks to consider the implications of the regulated firm being at least partly debt financed and the possibility of the firm choosing a duration for this debt finance that diverges from the length of the regulatory cycle.

In subsequent sections of the paper, Associate Professor Lally examines the implications of "the regulated firm being at least partly debt financed and the possibility of the firm choosing a duration for this debt finance that diverges from the length of the regulatory cycle". The focus of the paper is, as he clearly indicates in his statement of purpose, the term to maturity for the debt issued by a regulated firm. Associate Professor Lally is not concerned with the term to maturity of the proxy for the risk free asset which might be used in estimating the rate of return on that debt, or which might be used in estimating the rate of return on equity.

Associate Professor Lally begins his 2007 paper with an analysis in which the regulated firm's cost of debt is equal to the risk free rate of return. That the regulated firm's cost debt is equal to the risk free rate of return is a consequence of an initial – simplifying – assumption that the firm can borrow at the risk free rate of return. By assuming that the firm can borrow at the risk free rate, Associate Professor Lally is able to quickly demonstrate, in a setting without the complexities arising from risk, that:

(a) when the regulated firm is partly debt financed, and the term to maturity of the debt it issues is equal to the length of the regulatory period, the present value principle is satisfied: the present value of the returns to equity investors is equal to their initial equity investment; and

(b) when the regulated firm is partly debt financed, and the term to maturity of the debt it issues is not equal to the length of the regulatory period, the present value principle is not satisfied: the present value of the returns to equity investors is not equal to their initial equity investment.

[22] Lally (2007), page 73.

[23] Lally (2007), page 73.

Later in the paper, Associate Professor Lally assumes that corporate debt is risky, and that the regulator must take into account a premium for this risk. This complicates the analysis but Lally is again able to show that, when the term to maturity of the debt issued by the regulated firm is equal to the length of the regulatory period, the present value principle is satisfied.

In each of the analyses in his 2007 paper, Associate Professor Lally is concerned, not with the term of the proxy used to estimate the risk free rate of return, but with the question of whether the term to maturity of the debt issued by the regulated firm should be the same as the length of the regulatory period. When he claims that the term of the risk free rate should be equal to the length of the regulatory period, Associate Professor Lally is really asserting that, if the present value principle is to be satisfied, and if the regulated firm is able to issue debt at the risk free rate of return, then the term of the debt issued by the firm must be the same as the length of the regulatory period. His simplifying assumption – that the regulated firm can borrow at the risk free rate – confounds the term to maturity of the proxy for the risk free rate with the term to maturity of the debt issued by the regulated firm. When the simplifying assumption that the regulated firm can borrow at the risk free rate is dropped, Associate Professor Lally's view becomes clear: if the present value principle is to be satisfied, the term to maturity of the debt issued by the firm should be equal to the length of the regulatory period. He has nothing to say about the term to maturity of the proxy for the risk free rate of return.

We do not agree with the reasoning which leads Associate Professor Lally to his conclusion about the term to maturity of the debt issued by a regulated firm, and do not see that conclusion as being supported by the empirical evidence on debt raised by regulated firms. However, these are not issues in the present context. Despite his assertions early in his 2007 paper, Associate Professor Lally does not address the question of the term to maturity of the proxy for the risk free rate of return which is to be used in applying certain asset pricing models to estimate the rate of return on equity and the rate of return on debt. His paper addresses the implications of a regulated firm choosing a term to maturity for the debt it issues which diverges from the length of the regulatory period.

Appendix 2 to the Explanatory Statement also refers to a report which Associate Professor Lally prepared for the Queensland Competition Authority in 2010. In that report, he advises that the term to maturity of the proxy for the risk free asset must be equal to the length of the regulatory period if the present value principle is to be satisfied.

The 2010 report summarises, rather than repeats, the argument of Associate Professor Lally's earlier papers. It also extends his earlier analysis to take into account refinancing risk.

Associate Professor Lally's extension of his earlier analysis, through an examination of five options which might be available to a regulated firm, makes no reference to the term to maturity of the proxy for the risk free asset. He is concerned, again, with the implications of the regulated firm choosing a term to maturity for the debt it issues

which diverges from the length of the regulatory period, and assesses those implications using the present value principle.

Associate Professor Lally's summary, in 2010, of his earlier argument is revealing. He first notes the present value principle: in a regulated environment, in which output prices are set or capped so as to cover costs, these prices should have the property that the present value of the future cash flows equals the investment. He then contends that the risk free rate and the debt margin are part of this price setting decision, and must be chosen to satisfy the present value principle. The present value principle, Associate Professor Lally concludes, is satisfied when the risk free rate and the debt margin are chosen to match the regulatory cycle.[24]

Here, the error in his argument becomes clear. Associate Professor Lally assumes that, in determining the regulated rate of return, the regulated firm and the regulator are free to choose the risk free rate of return, and the debt margin, and should do so to satisfy the present value principle. This is not correct.

The rate of return allowed for regulatory purposes should provide the regulated firm with a return sufficient to efficiently finance the investments it must make in assets used to provide regulated services.

To determine the allowed rate of return – the rate of return commensurate with the efficient financing of investment – the regulated firm and the regulator usually rely on asset pricing models to estimate the returns on equity and on debt which are required by investors for investments of comparable risk to those made by the regulated firm. These asset pricing models model the behaviours of participants, in particular, of investors, in financial markets. If they are to provide estimates of the returns on equity and the returns on debt which are required by those investors, the parameters of those models must be estimated by reference to investor behaviour. Neither the regulated firm nor the regulator is free to arbitrarily choose the parameters of those models, or to choose the parameters subject to the constraint that the present value principle, applied in the context of price setting for the regulated firm, is satisfied.

In regulated tariff setting, the regulated firm and the regulator must choose the parameters of the asset pricing models they employ to provide estimates of the return on equity, and of the return on debt, which are estimates of the returns which investors require. If they do not, the regulated firm will not be provided with the opportunity to earn returns sufficient to efficiently finance its provision of regulated services, or may be provided with the opportunity to earn returns which are more than sufficient to efficiently finance the provision of those services.

Contrary to the assumption made by Associate Professor Lally, the risk free rate of return and the debt margin are not free to be chosen by the regulated firm or the regulator. In particular, the regulated firm and the regulator are not free to choose the term to maturity of the proxy for the risk free asset so that it is equal to the length of the regulatory period. Moreover, the present value principle does not require that the term to maturity of the proxy be the same as the regulatory period. Any choice of the proxy for the risk free asset, and any choice of the debt margin, used in the asset

[24] Lally (2010), page 8.

pricing models which the regulated firm and the regulator employ to estimate the return on equity and the return on debt will lead to a rate of return which, provided it is used to calculate the financing costs included in the present value of the firm's efficiently incurred costs, and to calculate the present value of the forecast revenue which recovers those costs, will satisfy the present value principle.

In subsequent sections of the Supporting Information, we explain that the risk free rate becomes a parameter in the estimation of the rate of return on equity, and in the estimation of the rate of return on debt, through the integral part it plays in the decisions which investors make about the portfolios of financial assets they choose to transfer wealth from one point in time to another. The risk free rate of return is a factor in investor demand for financial assets. It is not a factor which the suppliers of financial assets are free to choose, and if those suppliers of financial assets are regulated firms, it is not a parameter which they or their regulators are free to choose when setting allowed rates of return.

In the market for financial assets, regulated firms are "price takers". They are among many suppliers of financial assets, and have no monopsony power. They do not set the prices, or rates of return, on those financial assets. They can – and do – choose the term to maturity of the debt they issue, but they do not set the rate of return on that debt, or the rate of return on equity. Regulated firms, like many other firms, take the rate of return on equity, and the market price of debt of a particular maturity, as given in the market for financial assets.

The risk free rate of return, and the debt margin, enter into estimation of the market price of debt, and the risk free rate enters into estimation of the rate of return on equity set in the market for financial assets, through the way in which the portfolio decisions of investors are modelled. In the modelling of those portfolio decisions, investors take into consideration the availability of a risk free asset, and its price, together with the risky assets available in the market for financial assets and the expected returns on those assets. The regulatory period is not a factor in the portfolio decisions of investors.

The regulated firm, and the regulator, may choose the term to maturity of the debt issued by the regulated firm, and may do so by reference to the present value principle, as Associate Professor Lally suggests. They do not choose the term to maturity of the proxy for the risk free asset. The risk free asset is a factor in the portfolio decisions of investors.

If estimation of the rates of return on equity and debt used in determining reference tariffs requires use of an estimate of the risk free rate of return, the term to maturity of the proxy for the risk free asset must be determined by reference to the behaviour of investors. Only then will the regulated firm have the opportunity to earn the return which those investors require if they are to finance investment in the assets used to provide regulated services.

7.6.3 Studies by Professor Davis

In a report prepared for the Australian Competition and Consumer Commission in 2003, Professor Davis was explicit: "*The maturity chosen for the risk free rate should*

be equal to the length of the regulatory determination period (5 years in the case under consideration)".[25]

This conclusion followed from analysis using a simple example in which an initial investment of $200 in a regulated asset was returned, with a return, over two regulatory periods each of duration two years. Professor Davis's analysis is summarised in Table 14 below.

In this analysis, Professor Davis assumed that the regulated asset was financed with equity, and that this equity financing was equivalent to a "tracking portfolio" comprising a constant proportion, (1 – β), of the risk free asset, and a constant proportion, β, of the market portfolio, where β was the beta of the Sharpe-Lintner CAPM. The value of the tracking portfolio was, period by period, to be equal to the regulatory asset base, requiring that its value fell by the return of investment (regulatory depreciation). In the example, the return of investment was "straight line" (that is, $50 each year). β was assigned a value of 0.4.

The tracking portfolio was set up so that its expected cash flows would match the expected returns on the regulated asset, allowing a comparison to be made between the outlay required on the portfolio and the investment in the asset. If the outlay on the tracking portfolio were equal to the investment in the asset, the present value principle would be satisfied. In Professor Davis's terminology, NPV would be zero.

Over a multi-period horizon, the investment in the tracking portfolio would have to be reduced each period to reflect cash flows generated from the asset which were not reinvested (the return of capital or regulatory depreciation allowances). In Table 14, this reduction is represented by a series of portfolio withdrawals. In each period, the withdrawal is equal to the depreciation. It comprises a withdrawal of investment in the risk free asset, and a withdrawal of investment in the market portfolio, so that the tracking portfolio composition is always 60% of the risk free asset and 40% of the market portfolio (maintaining the ratio 1 - β : β, with β = 0.4).

Professor Davis first considered a case where the regulator calculates allowable cash flows using a two-period risk free rate in the Sharpe-Lintner CAPM: the term to maturity of the proxy for the risk free asset was equal to the length of the regulatory period. At time 0 – the beginning of the first regulatory period – the allowed rate of return was r_a^0. At time 2 – the beginning of the second regulatory period – the allowed rate of return was r_a^1.

The return on and of investment, and the composition of the tracking portfolio, over the two regulatory periods – over the life of the regulated asset – are summarised in Table 14.

[25] Kevin Davis, *Report on "Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC"*, prepared for the ACCC, 28 August 2003, page 4.

Table 14: Tracking portfolio: term to maturity of proxy for risk free asset equal to length of regulatory period

Time	**0**	**1**	**2**	**3**	**4**
Regulatory period		**1**		**2**	
Investment in asset	200				
Return of investment		50	50	50	50
Return on investment		$200r_a^0$	$150r_a^0$	$100r_a^1$	$50r_a^1$
Tracking portfolio	200				
Portfolio withdrawal		50	50	50	50
Portfolio composition:					
Risk free asset	120	90	60	30	0
Market portfolio	80	60	40	20	0
Portfolio return:					
Risk free asset		$120r_{02}$	$90r_{02}$	$60r_{22}$	$30r_{22}$
Market portfolio		$80r_M$	$60r_M$	$40r_M$	$20r_M$

The expected return on the tracking portfolio at time 1 is:

$120r_{02} + 80r_M = 200[(1 - 0.4)\, r_{02} + 0.4r_M] = 200[\, r_{02} - 0.4(\, r_M - \, r_{02})] = 200\, r_a^0$,

where r_{02} is the rate of return on the risk free asset at time 0 (the beginning of the first regulatory period), and r_M is the return on the market portfolio.

Similarly, the expected return on the tracking portfolio at time 2 is $150r_a^0$.

The expected return on the tracking portfolio at time 3 is:

$60r_{22} + 40r_M = 100[(1 - 0.4)\, r_{22} + 0.4r_M] = 100[\, r_{22} - 0.4(\, r_M - \, r_{22})] = 100\, r_a^1$,

where r_{22} is the rate of return on the risk free asset at time 2 (the beginning of the second regulatory period).

Similarly, the expected return on the tracking portfolio at time 4 is $50r_a^1$.

The tracking portfolio has expected cash flows equal to those of the regulated asset. Or almost, as Professor Davis acknowledges: the cash flows on the tracking portfolio may differ from the cash flows on the regulated asset because the tracking portfolio has some exposure to interest rate risk associated with those parts of the portfolio withdrawals at time 1 and at time 3 which are withdrawals of the risk free asset. They are withdrawals and liquidations, after one year, of bonds which have terms to maturity of two years (the regulatory period). This could be avoided, Professor Davis suggests, by establishing at time 0 a tracking portfolio comprising \$30 of a one year risk free bond and \$90 of a risk free bond with two years to maturity (together with an investment of \$80 in the market portfolio). However, the expected cash flows from the tracking portfolio would not then exactly match those from the investment in the regulated asset if there were a term premium in the yield curve.

The tracking portfolio which has the same expected cash flows as the regulatory asset, and no interest rate risk at the end of the second year (the date of the regulatory reset) comprises two assets: the market portfolio and the risk free asset with term to maturity of two years. Professor Davis concludes that this demonstrates that use of a proxy for the risk free asset which has a term to maturity equal to the length of the regulatory period when deriving the required return for the investment in the regulated asset generates cash flows which are "fairly priced".

Professor Davis then examines the consequences of the regulator using, at time 0, a proxy for the risk free asset which has a term to maturity longer than the regulatory period. He assumes a term of four years, which is the life of the regulated asset in his example.

At time 0, the tracking portfolio would still comprise an investment of $120 in the risk free asset (coupon bonds selling at par with term to maturity of four years) and an investment of $80 in the market portfolio.

Now, however, when the risk free asset must be sold at time 1 so that the value of the portfolio matches the depreciated value of the investment in the regulated asset and the portfolio composition is maintained at 60% of the risk free asset and 40% of the market portfolio (maintaining the ratio $1 - \beta : \beta$, with $\beta = 0.4$), the expected sale price is uncertain. This uncertainty can be hedged at time 0 by selling the risk free asset forward, but those sale proceeds (at time 2) will be less than the face value of the proxy for the risk free asset if the yield curve is upward sloping at time 0. The tracking portfolio established at time 0 and structured to avoid interest rate risk at time 2 (regulatory reset) does not generate expected cash flows as large as those of the investment in the regulated asset.

Professor Davis concludes that using a risk free asset with a term to maturity which exceeds the length of the regulatory period when determining the allowed rate of return provides an excess return to the regulated asset if, as is typically the case, there is a positive term premium in the yield curve.

Professor Davis's use of a tracking portfolio is an interesting application of the Sharpe-Lintner CAPM. Unfortunately, his analysis is incomplete and, therefore, does not lead to a correct conclusion.

Professor Davis assumes that the regulator is able to implement the correct rate of return on equity through its choice of the term to maturity of the proxy for the risk free asset. However, as we explained above, the regulator does not have freedom of choice in respect of the term to maturity of the proxy for the risk free asset. The proxy for the risk free asset must be chosen so that the rate of return is the market rate of return sought by investors. It must be the proxy relevant to those investors, and there is no reason to expect that its term to maturity should be equal to the length of the regulatory period.

In making an allowance for the return on equity, the regulator must take as given the market rate of return on equity. If that market rate of return is estimated using the Sharpe-Lintner CAPM, the model must incorporate an investor – and not a regulator – view of the risk free asset.

This can be seen from Professor Davis's example.

In Table 14, the returns on the tracking portfolio in each of the two years of the first regulatory period are:

Year 1: $120r_{02} + 80r_M$

Year 2: $90r_{02} + 60r_M$

These returns are constrained by the requirement – not included in Professor Davis's analysis – that that return on the tracking portfolio be the market return on equity:

$$120r_{02} + 80r_M = 200r_a^0$$

$$90r_{02} + 60r_M = 150r_a^0$$

where r_a^0 is the market rate of return on the regulated asset, determined at time 0 using the Sharpe-Lintner CAPM as Professor Davis assumes.

The second of these equations is, of course, a multiple (3/4) of the first. They both have the solution: $r_{02} = \frac{1}{3}(5r_a^0 - 2r_M)$.

If, as Professor Davis assumes, the tracking portfolio is to have the same expected cash flows as the regulated asset, its risk free rate, r_{02}, must be a function of the market rate of return on equity, r_a^0, and the return on the market portfolio, r_M. The market rate of return on equity incorporates an investor – not a regulator – view of the risk free rate of return. The return on the tracking portfolio must, therefore, incorporate that investor view of the risk free rate of return, and not the regulator view that the risk free rate be the rate of return on a proxy for the risk free asset which has term to maturity equal to the length of the regulatory period.

A similar result can be obtained for the second regulatory period.

Appendix 2 of the Explanatory Statement also notes (but does not examine in detail) subsequent work by Professor Davis for IPART, and a recent (2012) working paper.[26] Neither the work for IPART, nor Professor Davis's working paper, addresses the issue of the term to maturity of the proxy for the risk free asset. Their focus is the assumption to be made concerning the term to maturity of the debt issued by the regulated firm when determining regulated access prices. Professor Davis finds that the use of a debt maturity equal to the regulatory horizon involved in the resetting of allowable cash flows is consistent with achieving the goals of access price regulation. That is, like Associate Professor Lally, Professor Davis finds that, if the term to maturity of the debt issued by the regulated firm is different from the length of the regulatory period, the present value principle is not satisfied.

[26] Kevin Davis, *Determining Debt Costs in Access Pricing: A Report to IPART*, Appendix A to IPART, *Developing the approach to estimating the debt margin, Other Industries – Draft Decision*, February 2011; and Kevin Davis, "The Debt Maturity Issue in Access Pricing", Draft 3, 2 September 2012. IPART is the Independent Pricing and Regulatory Tribunal in New South Wales.

In his work for IPART, and in his 2012 working paper, Professor Davis no longer maintains that the term to maturity of the proxy for the risk free rate should equal the length of the regulatory period. Instead, he argues that the term to maturity of the debt of the regulated firm should equal the length of the regulatory period. Again, we do not agree, but that is not important in the present context. Professor Davis's more recent work does not support the view of the Explanatory Statement that the term to maturity of the proxy for the risk free asset should be the length of the regulatory period. It does not support the view that the term to maturity of the proxy should be, as is proposed in the Rate of Return Guidelines, five years when the regulatory period is five years.

7.6.4 GGT's estimate of the risk free rate of return

Provided the rate of return used in reference tariff calculation is the same as the rate of return used in determining the return component of total revenue, the present value principle to which the Explanatory Statement refers will be satisfied. Beyond this, the present value principle does not impose any constraint on the way in which the rate of return is to be estimated. It does not require that the term to maturity of a proxy for the risk free asset which might be used in estimating the rate of return be equal to the length of the access arrangement period.

Furthermore, the view that the term to maturity of a proxy for the risk free asset should be equal to the length of the access arrangement period, is not supported by the studies by Associate Professor Lally, and by Professor Davis, to which the Explanatory Statement refers. Those studies conclude that the term to maturity of the debt issued by a regulated firm should be equal to the length of the regulatory period. We do not agree with this conclusion, but that is not relevant to the issue of the term to maturity of the proxy for the risk free asset.

The term to maturity of the proxy for the risk free asset must be determined by reference to investor behaviour. If it is not – if the regulator chooses the term by reference to the regulatory context, by reference to the regulatory period – then there is no reason to expect that estimates of the returns on equity and on debt made using the resulting estimate of the risk free rate will be the returns required by investors if they are to finance investment in the assets used to provide regulated services.

Economic theory indicates that investors regard long term government bonds, rather than short term bonds, as the appropriate proxy for the risk free asset, and this theoretical view is supported by evidence from financial markets.

From the perspective of economic theory, investors do not desire wealth for its own sake, but for the consumption of goods and services which it makes possible. A risk averse investor will choose a stable – non-random – consumption plan, but will be unable to realise that plan by transferring wealth over time using a series of bonds with short terms to maturity. Although a short term bond may be riskless over its term to maturity, transferring wealth over longer horizons by rolling over short bonds is risky because future interest rates are stochastic. Long term bonds can finance stable long run consumption streams even in the face of time varying short term interest rates, and the ideal bond for this purpose is an inflation indexed consol (with infinite term to

maturity).[27] Inflation indexed consols are, however, unusual, and may not be among the traded financial assets for which returns can be observed.

Paragraph 62 of Appendix 2 to the Explanatory Statement notes the importance of investor horizons in the context of establishing the proxy for the risk free asset. Paragraphs 63 and 64 then report work by economic consultants Incenta, and by financial economists SFG Consulting (SFG), which indicates that market practitioners estimate the risk free rate of return from yields on bonds with terms to maturity of 10 years. However, this evidence from financial markets is dismissed in paragraph 69 of Appendix 2, which asserts that market practitioners often have an interest in 'talking up' investments, and that market practitioners are not investors.

We note that the market practitioners to which Incenta and SFG referred were independent expert valuers and investment banks. The independent expert valuers work within an explicit regime of regulation, comprising both formal statutory rules and less formal guidelines, which require that they be accountable for the results of their work.[28] There is no reason to expect that they would be concerned with 'talking up' investments, and none is provided in the Explanatory Statement. Investment banks invest in their own name, and provide advice to investors. They are close to investment decision making and can be expected to understand investor time horizons.

Paragraph 71 of the Explanatory Statement concludes, agreeing with Associate Professor Lally, that if there are inconsistencies, then the present value principle is a key consideration because it meets the requirements for efficiency in the NGR. The present value principle may, as we have indicated above, have role to play in the determination of the tariffs which can be charged by regulated firms. That will be consequence of the particular rules of the regulatory regime, and of the way in which they are to be applied. However, the present value principle has no role in the setting of the term to maturity of the proxy for the risk free rate of return and is, therefore, irrelevant to any assessment of evidence pertaining to investors' horizons for the purpose of setting the term of that proxy.

Paragraph 72 of Appendix 2 of the Explanatory Statement asserts that, because the return on equity is reset every five years, the use of a five year term for the risk free rate is consistent with ensuring that investors in a regulated firm have a reasonable opportunity to recover a return on investment. However, this is not the case: it is not consistent with those investors having a reasonable opportunity to recover a return on their investment which is commensurate with prevailing conditions in the market for financial assets. If the return on equity is reset every five years in a way which does not allow the firm to deliver market rates of return to its investors because the proxy

27 That long term bonds rather than short term bonds are relevant to consideration of the risk free asset appears to have been first raised by Modigliani and Sutch: Franco Modigliani and Richard Sutch (1966), "Innovations in Interest Rate Policy, American Economic Review, 56(1/2), pages 178-197. The theory was subsequently developed by, among others, Joseph E. Stiglitz (1970), "A Consumption-Oriented Theory of the Demand for Financial Assets and the Term Structure of Interest Rates", Review of Economic Studies, 37(3), pages 321-351; John Y Campbell and Luis M. Viceira (2001), "Who Should Buy Long-Term Bonds?", American Economic Review, 91(1), pages 99-127; and Jessica A. Wachter (2003), "Risk aversion and allocation to long-term bonds", Journal of Economic Theory, 112, pages 325-333.

28 See Australian Securities and Investments Commission, Regulatory Guide RG 111, *Contents of Experts Reports*, and Regulatory Guide RG 112, *Independence of Experts*.

chosen for the risk free asset has a term to maturity which is short and leads to returns which are too low, those investors will not continue to finance efficient investment in pipelines in the long term interests of consumers of natural gas.

Contrary to the view expressed in paragraph 444 of the Explanatory Statement, the present value principle does not provide any reason for equating the term to maturity of the proxy for the risk free asset with the length of the regulatory period. Were the rate of return on equity and the rate of return on debt to be estimated using the yields on Commonwealth Government bonds with terms to maturity closely approximating the term of five years usually adopted for the regulatory period, there would be no reason to expect that either of those rates of return would contribute to the achievement of the allowed rate of return objective.

GGT has, therefore, departed from the from the Rate of Return Guidelines in the matter of the term to maturity of the Commonwealth Government bonds used to estimate the risk free rate of return.

GGT notes that, after examining the issues, the Australian Energy Regulator (AER) adopted Commonwealth Government bonds with terms to maturity of 10 years as the proxy for the risk free asset to be used in applying its Rate of Return Guideline.

In its August 2013 Draft Rate of Return Guideline, the AER advised that it intended to adopt a term of 10 years for the proxy for the risk asset for the following reasons:

(a) the AER was more persuaded by the arguments for a 10 year term than by the arguments for a five year term;

(b) the AER had adopted a 10 year term in past decisions; maintaining this previous position, in the absence of good reasons for change would promote certainty and predictability in decision making;

(c) maintaining a 10 year term would avoid some practical complexities in the estimation of certain return on equity parameters (specifically, the market risk premium) that would result from a change from a 10 year to five year term; and

(d) the difference in the overall rate of return between a 10 year and five year return on equity was unlikely to be material.

In the context of setting the rate of return on equity, the main argument for using a long term proxy for the risk free asset was, the AER advised, that equity in an ongoing infrastructure business can be expected to generate regular cash flows into the long term and, potentially, in perpetuity. The term of proxy should, then, match the long life of those cash flows and of the underlying physical assets.

The AER noted that this was the view of advisors to practitioners applying the Sharpe-Lintner CAPM. Pratt and Grabowski, and Damodaran, for example, had observed that, in general, an equity investment in an ongoing business is long term and, in consequence, the term of the equity in an ongoing business should be measured as

the duration of a long-term – and potentially infinite – series of cash flows.[29] Pratt and Grabowski, and Damodaran, the AER noted, concluded that long term government bonds should be used in estimating the a risk free rate of return on equity, and Damodaran advised that the use of bonds with terms to maturity of 10 years was usually appropriate.

The AER also advised that bonds with terms to maturity of 10 years were used by business valuations practitioners for estimation of the risk free rate of return. Furthermore, the KPMG Valuation Practices Survey 2013 had reported that 85% of its survey respondents used the yield on 10 year government bonds as a proxy for the risk free rate in Australia.

This practice of using of Commonwealth Government bonds with term to maturity of 10 years as the proxy for the risk free asset is, as we noted above, supported by economic theoretical arguments (although the AER does not explicitly refer to them).

GGT has therefore estimated the risk free rate of return using yields on Commonwealth Government bonds with terms to maturity of 10 years.

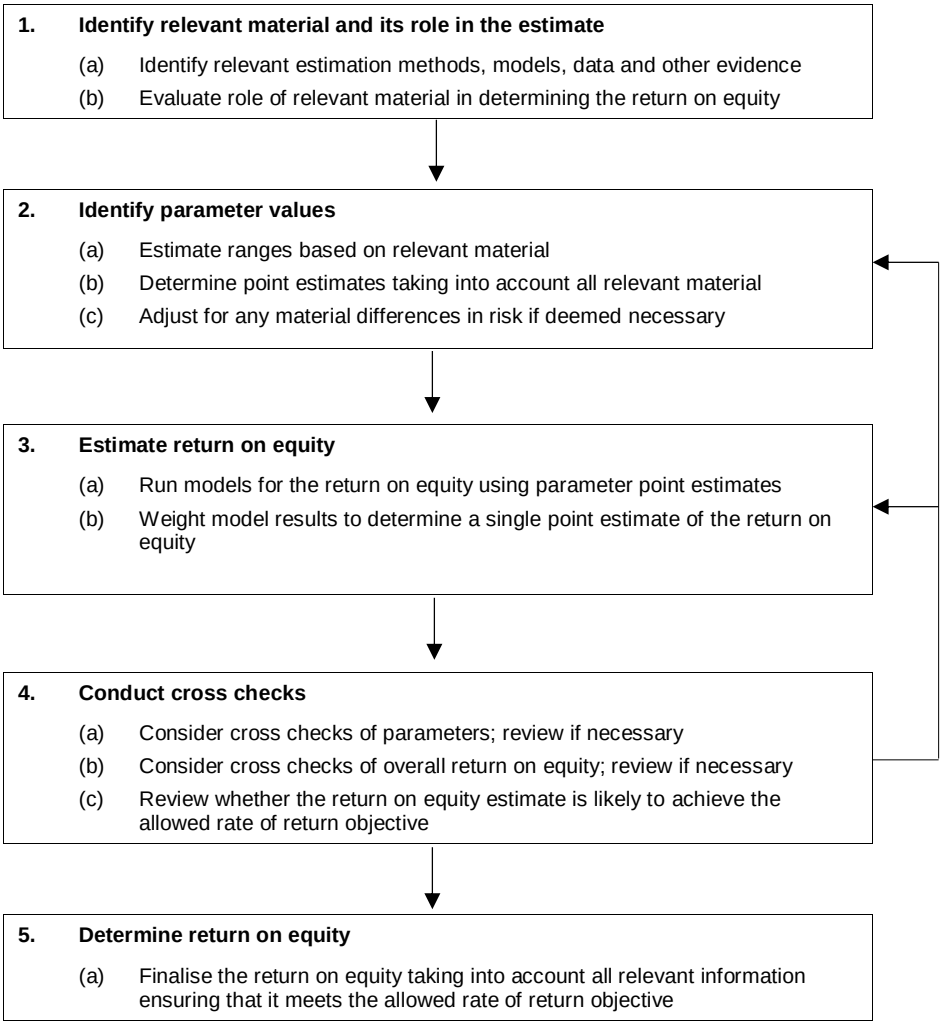
GGT has estimated the risk free rate of return for its access arrangement revisions proposal as an average of yields on Commonwealth Government bonds reported by the Reserve Bank of Australia for the period of 40 trading days to 30 June 2014. The estimate GGT has obtained is 3.73%.

7.7 Estimating the return on equity

The benchmark efficient entity of the allowed rate of return objective of rule 87 is financed by equity and debt. The Rate of Return Guidelines require that rate of return on the equity financing the benchmark efficient entity be estimated by following the five steps of the approach summarised in Figure 1 of the guidelines. Figure 1 is reproduced as Figure 4 below.

[29] Shannon Pratt and Roger Grabowski (2010), *Cost of Capital: Applications and Examples*, 4th ed., Hoboken: Wiley; and Aswath Damodaran, *'What is the risk free rate? A search for the basic building block'*, December 2008, available at http://pages.stern.nyu.edu/~adamodar/.

Figure 4: Five steps in estimating the rate of return on equity



The way in which GGT has followed these five steps in estimating the return on equity used in determining the proposed allowed rate of return for the GGP Access Arrangement revision proposal is explained in the paragraphs which follow.

7.7.1 Identifying relevant material and its role in the estimate

The Rate of Return Guidelines indicate that the first step in estimating the return on equity – identifying relevant material and its role in estimation – has been largely completed in the process of making the guidelines.

Paragraph 113 of the Rate of Return Guidelines advises that the ERA has reviewed alternative asset pricing models and approaches, and has concluded that the Sharpe-Lintner CAPM is, at the present time, the only model which is relevant for informing estimation of the return on equity for a regulated firm.

The Sharpe-Lintner CAPM explains the expected rate of return on a financial asset in terms of the rate of return on the risk free asset and a premium for risk:

$$E_t(r_{i,t+1}) = r_{f,t} + [E_t(r_{M,t+1}) - r_{f,t}] \times \beta_i,$$

where

(a) $E_t(r_{i,t+1})$ is the time t expected return at time $t+1$ on financial asset i;

(b) $r_{f,t}$ is the return on the risk free asset at time t;

(c) $E_t(r_{M,t+1})$ is the time t expected return at time $t+1$ on the market portfolio of financial assets;

(d) $E_t(r_{M,t+1}) - r_{f,t}$ is the market risk premium at time t;

(e) β_i is the beta of financial asset i, which is defined as

$\beta_i = \text{cov}(r_i, r_M)/\text{var}(r_M)$; and

(f) $[E_t(r_{M,t+1}) - r_{f,t}]$ x β_i is the premium for the risk to which an investor is exposed at time t when holding asset i.[30]

Appendix 9 of the Explanatory Statement provides a summary of portfolio theory, and of the way in which that theory can be used to derive the Sharpe-Lintner CAPM.[31]

In an Appendix to this section of the Supporting Information we re-examine the material in Appendix 9 of the Explanatory Statement. The Sharpe-Lintner CAPM is not referred to in rule 87 of the NGR. Its use, as recommended by the Rate of Return Guidelines, is guided by economic principles. Empirical analysis does not provide much support for the model.[32] In re-examining the material of Appendix 9, we are concerned to ensure that our application of the Sharpe-Lintner CAPM is in the way intended in the Rate of Return Guidelines, and is consistent with the relevant underlying economic theory.

30 This is the formulation of the Sharpe-Lintner CAPM set out and discussed in Appendix 8 of the Explanatory Statement.

31 Appendix 9 refers to "modern portfolio theory", the single period mean-variance analysis first proposed by Markowitz in 1952. In subsequent sections of the Supporting Information, we continue to refer to this analysis as "portfolio theory", recognising that the theory of portfolio choice has advanced significantly since Markowitz's pioneering work.

32 See, for example, Eugene F. Fama and Kenneth R. French (1992), "The Cross-Section of Expected Stock Returns", Journal of Finance, 47(2): pages 427-465; and Eugene F. Fama and Kenneth R. French (1996), "Multifactor Explanations of Asset Pricing Anomalies", Journal of Finance, 51(1): pages 55-84. An Australian study reporting that "the evidence that beta is priced is, at best, marginal" is Nick Durack, Robert B. Durand, and Ross A. Maller (2004), "A best choice among asset pricing models? The Conditional Capital Asset Pricing Model in Australia", Accounting and Finance, 44: pages 139-162. The limited empirical support for the Sharpe-Lintner CAPM is discussed in Peter Bossaerts (2012), *The Paradox of Asset Pricing*, Princeton: Princeton University Press, chapter 3; John H. Cochrane (2005), *Asset Pricing*, revised, Princeton: Princeton University Press, chapter 20and Haim Levy (2011), *The Capital Asset Pricing Model in the 21st Century: Analytical, Empirical and Behavioural Perspectives*, Cambridge: Cambridge University Press, chapter 7.

7.7.2 Identifying parameter values

If the Sharpe-Lintner CAPM is to be used to estimate a rate of return on equity at a point in time, the values of three parameters must be identified. These are:

(a) the risk free rate of return at that point in time (r_f);

(b) the beta of the asset for which the rate of return is to be determined (β_i); and

(c) $E(r_M) - r_f$, which is often referred to as the market risk premium.

GGT's estimation of the risk free rate of return for use in determining its proposed allowed rate of return was discussed in section 7.6 above. In the subsections which follow, we identify the value for beta to be used in estimating the return on equity component of the proposed allowed rate of return, and the market risk premium to be used in estimating that return on equity.

The allowed rate of return of rule 87 is to be the efficient financing cost of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services. That is, the allowed rate of return is not the rate of return of the service provider but the rate of return of a benchmark entity which has risks similar to those of the service provider in the provision of reference services. If the return on equity is to be estimated in a way which contributes to achievement of the allowed rate of return objective, and the Sharpe-Lintner CAPM is to be used for that purpose, then the beta used in applying that model must be the beta of the benchmark efficient entity. Unlike the risk free rate of return and the market risk premium, the beta is entity-specific.

Before identifying a value for beta, we review the role of the benchmark efficient entity as this is set out in the Rate of Return Guidelines and the Explanatory Statement, and the implications of the choice of the benchmark for estimation of the return on equity.

7.7.3 The benchmark efficient entity and similar risk

Although not its primary purpose, paragraph 163 of the Explanatory Statement sets out the broad approach to parameter identification for the purpose of determining the allowed rate of return of rule 87:

(a) a conceptual definition of the benchmark efficient entity of rule 87(3) is established;

(b) evidence from actual "comparator" entities, which resemble the conceptual entity, is gathered; and

(c) this evidence is used to inform identification of the parameters used to estimate the return on equity (and the return on debt).

In the following paragraphs of this section we note the conceptual definition of the benchmark efficient entity, and examine the way in which evidence from comparator entities is to be used to inform identification of the parameters used to estimate the

return on equity (and the return on debt). The evidence itself, and the use of that evidence in identifying specific parameter values, are matters left to subsequent sections of the Supporting Information.

The benchmark efficient entity is defined, conceptually, in paragraph 58 of the Rate of Return Guidelines. The benchmark efficient entity is:

An efficient 'pure play' regulated gas network business operating within Australia without parental ownership, with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services.

Rule 87(3), the Explanatory Statement notes, requires that account be taken of the risks associated with the provision of reference services. This could be done through either a single benchmark, which is then adjusted, or through multiple benchmarks, each of which corresponds to a particular configuration of reference services. The ERA's preference is to work with a single benchmark (Explanatory Statement, paragraph 198).

The efficient financing costs, with which the allowed rate of return is to be commensurate, are then to be estimated using evidence from a sample of comparator entities with efficient financing costs that are judged to be similar to the benchmark efficient entity (Rate of Return Guidelines, paragraph 59). The sample of comparator entities which the ERA has used to identify the range of an equity beta for a benchmark efficient gas pipeline business is listed in Table 20 of the Explanatory Statement.

The benchmark efficient entity is to have a degree of risk similar to that of the service provider in respect of the provision of reference services and, in establishing its sample of comparator entities, the ERA has started from the presumption that the risks of gas pipelines in Australia are generally similar (Explanatory Statement, paragraph 165).

Paragraph 166 of the Explanatory Statement advises that the ERA is open to the potential for some risks of the service provider to be materially different from the corresponding risks of the benchmark efficient entity. Judgement is then required to determine whether any adjustment should be made to individual parameter values, to the return on equity, to the return on debt, or to the overall rate of return in order to account for any material and substantiated difference between the risks of the service provider in the provision of reference services and the risks associated with the benchmark efficient entity (Rate of Return Guidelines, paragraph 60).

GGT is of the view that a material difference in risk between a service provider for which an allowed rate of return is being determined and the benchmark efficient entity is precluded by the requirement for similarity in rule 87(3). However, a difference in risk may arise between the service provider and the entities in the sample of comparators from which data are to be obtained for the purpose of estimating efficient financing costs. The entities in the sample may have degrees of risk different from that of the service provider if they serve different markets for pipeline services (for example markets for transmission and distribution services), and undertake the provision of other – regulated and unregulated – services (for example unregulated

pipeline services and regulated electricity distribution services) within the corporate entity which provides regulated pipeline services.

The Rate of Return Guidelines advise that the ERA will consider proposals to adjust individual parameters, the return on equity, the return on debt, or the overall rate of return for the benchmark efficient entity, in order to account for any material and substantiated risk differential between the comparator entities and the service provider.

Paragraph 202 of the Explanatory Statement goes further: if a service provider is of the view that there is a material risk differential, then it should provide sufficient information to allow the ERA to weigh up and account for the relative differences in any risks between the sample of comparators and the service provider providing the reference services.

We note that, although adjustments might be made to individual parameter values, to the rate of return on equity or debt estimated using those parameter values, or to the overall rate of return, those adjustments are not intended to fully align the benchmark efficient entity and the service provider: the benchmark entity should reflect the most efficient financial means of delivering the reference service (Explanatory Statement, paragraph 167).

Furthermore, the benchmark efficient entity is to have a degree of risk similar to that of the service provider in respect of the provision of reference services, and paragraph 189 of the Explanatory Statement advises that the term “similar” recognises the practicalities of approximating risk profiles. This requirement for similarity extends to similarity between the efficient financing practices of certain businesses – the comparators – and the benchmark (Explanatory Statement, paragraph 190).

The key conceptual issue here is, as paragraph 191 of the Explanatory Statement makes clear, the meaning of “similar”: how wide is the range of allowed differences in risks for entities which are to be taken to be similar? Unfortunately, no guidance is provided on this issue in either the Rate of Return Guidelines or the Explanatory Statement. The discussion around sample size in paragraphs 191 to 193 of the Explanatory Statement does not address this issue. The meaning of ‘similar’ must be settled to facilitate identification of a homogeneous population before any consideration is given to estimation and sample size.

Again, the requirement of rule 87(3) is for the benchmark efficient entity to have a degree of risk which is similar to that of the service provider in respect of the provision of reference services. The Explanatory Statement contends that, in this context, the risks that matter for the investor, and hence for the rate of return, are systematic risks (paragraph 203).

If a service provider is of the view that there is a material risk differential, then the first steps to be taken are identification of the range of potential risks, and the classification of those risks as systematic or non-systematic (Explanatory Statement, paragraph 205). An assessment must then be made of whether the identified risks are material, and hence whether they need to be accounted for in the rate of return (Explanatory Statement, paragraph 206).

The key risks to be considered in assessing the degree of risk of the service provider in respect of the provision of reference services are listed in paragraph 207 of the Explanatory Statement. They are:

(a) revenue risk under the price cap applying to the service provider;

(b) input price risk;

(c) financial risk; and

(d) political and regulatory risk.

7.7.4 Equity beta

Paragraph 137 of the Rate of Return Guidelines advises that empirical evidence must be used to inform a decision about the equity beta, and that the ERA has undertaken its own empirical analysis based on the approach of Professor Henry, who estimated betas for the Australian Energy Regulator in 2009.

From its analysis, the ERA has formed the view that an estimate of beta in the range 0.50 to 0.70 is appropriate (Rate of Return Guidelines, paragraph 140).

In the context of making a particular regulatory decision, judgement must be exercised in arriving at a point estimate of beta which best reflects the systematic risk of the benchmark efficient entity of the allowed rate of return objective (Rate of Return Guidelines, paragraph 141). This exercise of judgement is required, at least in part, because the relevant empirical evidence supports a view that there is some downward bias in equity beta estimates that are less than one, and some upward bias in beta estimates which are greater than one.

The Explanatory Statement advises that a point estimate of 0.6, the mid-point of its range for the beta estimate, could be adopted (paragraph 644). The estimate of the equity beta is, however, to be an estimate of the beta for the benchmark efficient entity of the allowed rate of return objective. If there were material and substantiated risk differences between the companies for which data were obtained for the purpose of estimating beta and the service provider which was the subject of a particular regulatory decision, then a further adjustment to beta may be considered (Explanatory Statement, paragraph 645.)

The companies for which data were obtained by the ERA for the purpose of estimating an equity beta are described in Appendix 18 to the Explanatory Statement. Those companies, and the brief descriptions provided, are listed in Table 15.

Table 15: Companies used in ERA equity beta estimation

Company	Sector	Description (at April 2013)
APA Group (APA)	Energy	Owns and operates gas transmission and distribution assets across Australia, and holds minority interests in other energy infrastructure businesses.
DUET Group (DUE)	Utilities	A registered managed investment scheme and three public companies; which trade on the Australian Securities Exchange (ASX) as one entity (DUET Group) which invests in energy utility assets, including gas pipelines and electricity distribution networks, in Australia and New Zealand.
Envestra Limited (ENV)	Utilities	Operates natural gas distribution networks and transmission pipelines in South Australia, Queensland and the Northern Territory.
Hastings Diversified Utilities Fund (HDF)	Financial	A fund which has invested in a utility infrastructure assets including gas transmission and distribution pipelines, electricity generators (including hydro and wind generation assets, and electricity transmission and distribution networks). (In the course of acquisition APA Group, the securities of Hastings Diversified Utilities Fund were suspended from ASX quotation on 23 November 2012, in accordance with listing rule 17.4.)
Spark Infrastructure (SKI)	Utilities	A specialist utility infrastructure fund with investments in electricity distributors SA Power Networks, CitiPower and Powercor.
SP AusNet (SPN)	Utilities	Owns and operates electricity transmission, and electricity and gas distribution, assets in Victoria.

The Explanatory Statement advises that three of the companies included in the set from which data were obtained for beta estimations for previous regulatory decisions have been excluded from the list in Table 15. These three companies, Gas Net Australia, Alinta Limited and Jemena, had ceased trading (Explanatory Statement, paragraph 772).

The estimates which are advanced in support of the range for the equity beta in the Rate of Return Guidelines are shown in Table 16.

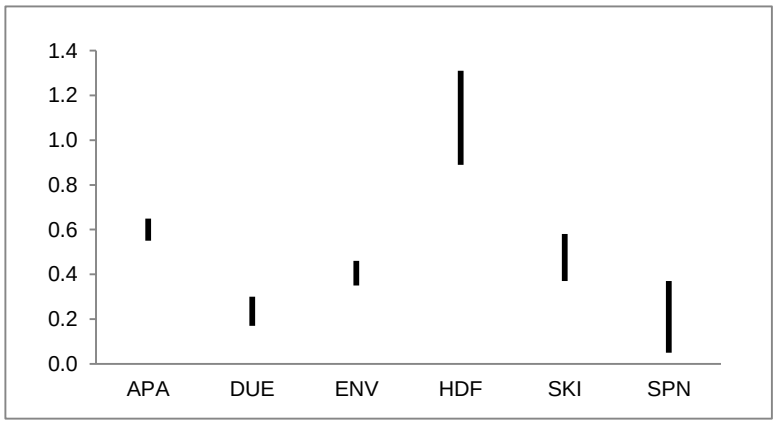
Table 16: ERA equity beta estimates

	APA	DUE	ENV	HDF	SKI	SPN
2012 analysis						
OLS estimates	0.60	0.30	0.37	1.19	0.52	0.27
LAD estimates	0.60	0.24	0.35	0.89	0.39	0.25
2013 analysis						
OLS estimates	0.61	0.23	0.37	1.20	0.54	0.12
LAD estimates	0.56	0.24	0.35	0.97	0.44	0.26
April 2008 to April 2013 data set						
Gearing	54.2%	74.2%	68.8%	39.4%	44.4%	61.1%
OLS estimates	0.59	0.17	0.44	1.20	0.54	0.05
LAD estimates	0.55	0.23	0.44	1.11	0.37	0.26
Robust ML estimates	0.63	0.25	0.45	1.00	0.48	0.30
Thiel Sen estimates	0.56	0.27	0.45	1.01	0.39	0.22
Adjusted 2013						
Gearing	54.2%	74.2%	68.8%	39.4%	44.4%	61.1%
OLS estimates	0.59	0.27	0.44	1.31	0.58	0.37
LAD estimates	0.55	0.23	0.44	1.09	0.37	0.26
Robust ML estimates	0.65	0.22	0.46	0.99	0.44	0.31
Thiel Sen estimates	0.56	0.26	0.45	1.04	0.41	0.25

Source: Explanatory Statement, Tables 21, 22 and 33.

The ranges of the beta estimates for the companies from which data were sourced by the ERA is shown in Figure 5. The range extends from 0.05 (SP AusNet) to 1.39 (Hastings Diversified Utilities Fund).

Figure 5: ERA equity beta estimates



The AER has now released equity beta estimates for the same set of companies which were prepared, recently, by Professor Henry.[33] These estimates are summarised in Table 17.

[33] Olan T. Henry, *Estimating β – An Update*, April 2014, available at http://www.aer.gov.au/node/18859

Table 17: Henry (2014) equity beta estimates

	APA	DUE	ENV	HDF	SKI	SPN
Weekly sampling						
Longest series						
OLS estimates	0.60	0.28	0.30	1.03	0.33	0.29
LAD estimates	0.59	0.21	0.28	0.71	0.32	0.28
After "dot-com", excl. GFC						
OLS estimates	0.64	0.30	0.37	0.90	0.34	0.47
LAD estimates	0.53	0.26	0.34	0.72	0.41	0.47
Five years to 28 June 2013						
OLS estimates	0.54	0.24	0.38	1.02	0.30	0.27
LAD estimates	0.54	0.22	0.39	0.78	0.22	0.41
Monthly sampling (OLS estimates only)						
Longest series	0.68	0.33	0.30	0.29	0.25	0.33
After "dot-com", excl. GFC	0.70	0.29	0.26	0.57	0.13	0.53
Five years to 28 June 2013	0.77	0.32	0.43	0.11	0.21	0.36

The ranges of the beta estimates for the companies from which data were sourced by Professor Henry are shown in Figure 6. The range extends from 0.11 (Hastings Diversified Utilities Fund) to 1.03 (Hastings Diversified Utilities Fund).

Figure 6: Henry (2014) equity beta estimates

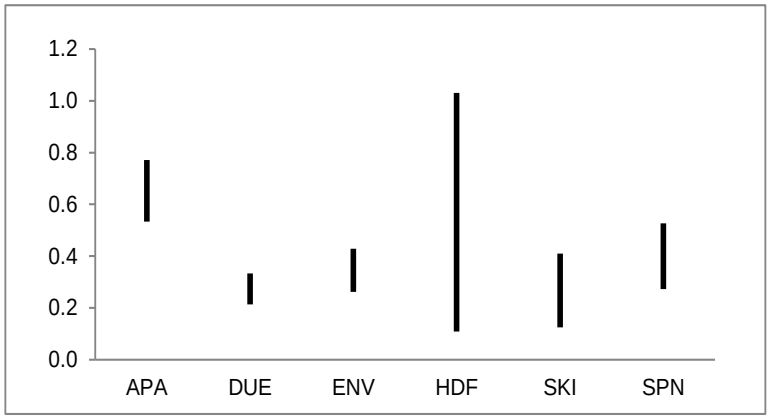


Table 16 and Table 17, and Figure 5 and Figure 6, show diversity in the estimates of the equity betas for the six Australian energy networks businesses for which share price data are available for beta estimation.

Hastings (HDF) appears to be very different from the others. DUET Group owns the Dampier to Bunbury Natural Gas Pipeline, but earns greater revenues from its Victorian electricity and gas distribution businesses. Both the ERA and Henry estimates place its beta closer to that of gas distributor Envestra (ENV) than that of APA Group (APA), which has a strong focus on gas transmission. Spark Infrastructure (SKI) and SP AusNet (SPN) earn revenues mainly from the provision of electricity network services; they also have significant distribution businesses (in the case of SP AusNet in both electricity and gas).

Similarity in risk is difficult to discern from Table 16 and Table 17 (or from Figure 5 and Figure 6), as is a clear indication that the equity beta for the benchmark efficient gas pipeline service provider should be in the range 0.50 to 0.70.

Beta is, as we discuss in subsection A7.1 of the Appendix to this section of the Supporting Information, a measure of risk. The systematic risk of asset i, $\beta_i^2 \mathrm{var}(r_M)$, is that part of the risk of the asset attributable to the risk of the market portfolio. As we explain in subsection A7.1, only the systematic risk of financial asset i is priced: the market equilibrium rate of return on the asset only compensates an investor for bearing systematic risk.

The Explanatory Statement notes, in paragraph 207, that the key risks to which an infrastructure asset is exposed are revenue risk, input price risk, financial risk and political/regulatory risk. In the case of gas pipelines, revenue risk is the result of potential variability in revenue due to variability in throughput (Explanatory Statement, paragraph 208). This variability in throughput may result from variability in gas supply, pipeline operating and technical problems, competition in the market for energy services, and variability in downstream demand. Of these factors, variability in downstream demand has the potential to be outside the control of asset owners and is, therefore, a systematic risk (Explanatory Statement, paragraph 212).

Previous regulatory decisions have recognised this downstream demand risk as being an important characteristic of the risks inherent in the provision of pipeline services using the GGP. Not only is the GGP exposed to changes in pipeline throughput as users change their gas usage in response to changes in economic conditions. The GGP is also exposed to those users seeking to reduce their contracted capacities, when commodity prices are low and, on occasion, seeking to terminate their contracts, or defaulting, when their own production operations become uneconomic.

In its May 2005 Final Decision on a proposed access arrangement for the GGP, the ERA noted that Australian regulators had adopted a cautious approach to beta estimation and, given the limited amount of empirical evidence available, had adopted an estimate of 1.0. However, in setting a beta, the ERA was cognisant of the fact that Western Australian transmission pipelines served markets that were predominantly related to mining and mineral processing. Through the demand risk associated with serving these markets, Western Australian pipelines may be exposed to higher levels of systematic risk that should be reflected in higher estimates for beta.[34]

The ERA's May 2005 Final Decision indicated that the equity beta for the GGP was in the range 0.80 to 1.33.

Proposed revisions to the GGP Access Arrangement were submitted to the ERA, for approval, in March 2009 and, in its Draft Decision on these revisions, the ERA advised that an appropriate range for the equity beta was 0.80 to 1.20.

[34] Economic Regulation Authority, *Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline*, 17 May 2005, Appendix 1, pages 211-212.

Later, in its May 2010 Final Decision, the ERA noted:

(a) the Covered Pipeline had a small number of users, users with operations primarily in the mining industry (paragraph 247);

(b) these users were supplied under gas transportation agreements which were, in essence, long term take-or-pay contracts, and which substantially reduced the volume and price risks associated with the provision of pipeline services (paragraph 248);

(c) existing customers and/or new users could reasonably be assumed to provide continued demand for pipeline capacity as existing gas transportation agreements expired (paragraph 248);

(d) the AER had observed that the nature of the gas industry was such that the equity beta of a benchmark efficient service provider was likely to be less than 1.0 (that is, less than the beta of the market portfolio) (paragraph 244);

(e) the limited volume and price risk associated with the capacity of the Covered Pipeline pointed to a beta of 1.0 being a reasonable upper bound (paragraph 249); and

(f) a reasonable lower bound for beta remained 0.80 (paragraph 245).[35]

Prior regulatory decisions have, then, established the equity beta for the Covered Pipeline as being in the range 0.80 to 1.33, recognising the demand risk associated with the transportation of gas primarily for mining and mineral processing in relatively remote areas of Western Australia. Those decisions have reflected uncertainty about the range through the progressive reduction in the upper limit for beta from 1.33 to 1.00. They have maintained the lower limit at 0.80.

Both the ERA and the AER have, since 2009, refined their estimation of equity betas, now making greater use of the results of econometric studies which have provided beta estimates for those Australian energy networks businesses for which share price data are available. This refinement might be relevant if it were possible to ascertain from that work a benchmark entity with degree of risk similar to that of the service provider – GGT – in its provision of the Firm Service reference service using the Covered Pipeline.

However, none of the entities for which the beta estimates of Table 16 (or Table 17) have been made is similar to the Covered Pipeline in respect of the users and end users of gas which it serves. None has the same small number of users concentrated in the mining and mineral processing sectors. Each may serve a small number of users (end users consuming large quantities of gas, and gas retailers), but those users themselves supply gas or electricity to a wide range of customers located in major – and growing – urban areas. This diversity in customer bases is illustrated in Table 18.

[35] Economic Regulation Authority, *Final Decision on GGT's Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 13 May 2010.

Table 18: Customer bases of companies used in ERA equity beta estimation

Company	Location of operations	Customer connections
APA Group (APA)		
Roma to Brisbane Pipeline		
Allgas Energy	Brisbane gas distribution	87,271
Envestra (Queensland)	Brisbane gas distribution	83,572
APA Gas Net		
Envestra (Victoria)	Melbourne and Victorian gas distribution	590,439
SPN Gas Distribution	Central and western Victorian gas distribution	608,288
Multinet Gas	Melbourne gas distribution	660,000
Moomba Sydney Pipeline		
Jemena Gas Networks	Sydney and regional New South Wales gas distribution	1,265,211
ActewAGL	Canberra gas distribution	133,462
Envestra (Wagga Wagga)	Regional New South Wales gas distribution	18,315
Goldfields Gas Pipeline		
Large end users	Pilbara and Goldfields regions	15
Horizon Power (Leonora)	Leonora electricity supply	401
ATCO Gas Australia	Kalgoorlie gas distribution	13,500
Esperance Power	Esperance electricity distribution	13,477
DUET Group (DUE)		
United Energy Distribution	Melbourne electricity distribution	640,000
Multinet Gas	Melbourne gas distribution	660,000
Dampier to Bunbury Natural Gas Pipeline	Pilbara and South Western Australia (includes end users on Mid West and South West Gas Distribution Systems)	676,287
Envestra (ENV)		
Albury	Regional New South Wales gas distribution	206,360
South Australia	Adelaide and South Australian gas distribution	395,774
Victoria	Melbourne and Victorian gas distribution	590,439
Queensland	Brisbane gas distribution	83,572
Spark Infrastructure (SKI)		
CitiPower	Melbourne electricity distribution	320,000
Powercor	Melbourne electricity distribution	748,000
SA Power Networks	South Australian electricity distribution	830,000
SP AusNet (SPN)		
SPN Electricity Transmission		
CitiPower	Melbourne electricity distribution	320,000
Powercor	Melbourne electricity distribution	748,000
United Energy Distribution	Melbourne electricity distribution	640,000
SPA Electricity Distribution	Eastern Victoria	640,000
Jemena Electricity Networks	Melbourne electricity distribution	329,428
SPN Gas Distribution	Central and western Victorian gas distribution	608,288

Table 18 shows five of the six companies used in the ERA (and Henry) beta estimations. The sixth, Hastings Diversified Utilities Fund, has been acquired by APA Group. The numbers of customer connections shown in the table have been obtained from company web sites and regulatory documents. The numbers of connections are

not all at the same date, but extend over the period 2009 to 2013, and they cover connections ranging from small households to large industrial users. In some cases, the numbers provided are clearly not precise. In the cases of the Kalgoorlie gas distribution and Esperance electricity distribution systems, which are supplied from the GGP, GGT has made estimates of the number of end users from information on gas flows.

Although the quality of the information is poor, it is indicative of the number of end users of energy served and where they are served. Five of the six companies used in the ERA (and Henry) beta estimations deliver energy to over 1 million end users, many of whom are located in the State capital cities. APA Group is primarily a gas transmission business delivering gas to end users mainly in Brisbane, Sydney and Melbourne. Envestra is a gas distributor with networks in Brisbane, Melbourne and Adelaide. Spark Infrastructure is primarily an electricity distributor serving Melbourne and Adelaide. DUET Group combines electricity and gas distribution, in Melbourne, with gas transmission to Perth and the south west of Western Australia. SP AusNet has a major electricity transmission business serving Melbourne and eastern Victoria, but is also a gas distributor in central and western Victoria.

None of the companies for which the beta estimates of Table 16 have been made is similar to the Covered Pipeline in respect of the users and end users of gas which it serves. None has the same small number of users concentrated in remote locations and in the mining and mineral processing sectors.

The ERA's earlier assumption made when estimating beta – that pipeline users are supplied under gas transportation agreements which substantially reduced the volume and price risks associated with the provision of pipeline services – remains valid. However, given the remote location of the pipeline and the relatively narrow business focus of each of its users, there can be no expectation that current customers and/or new users can reasonably be assumed to provide continued demand for pipeline capacity as existing gas transportation agreements expire. [redacted]

The estimates in Table 16 (and also those in Table 17) do not provide evidence that the equity beta for the Covered Pipeline lies below the range – 0.80 to 1.33 – established by the ERA in 2005, and not provide evidence that it lies below the ranges 0.80 to 1.20 and 0.80 to 1.00 established in 2010.

The GGP is exposed to downstream demand risk which is a form of systematic risk. This risk must be reflected in the equity beta estimate for the Covered Pipeline if that estimate is to lead to a return on equity which contributes to achievement of a rate of return commensurate with the efficient financing costs of a benchmark efficient entity

with a degree of risk similar to that of the service provider in respect of the provision of reference services.

This downstream demand risk might be reduced or eliminated by an individual investor choosing a portfolio in which the risk attributable to holding an equity position in the Covered Pipeline is offset by the holding of other assets for which returns are expected to increase in the circumstances of declining commodity prices which increase the risk of the position in the GGP. However, that is not relevant to an appropriate value of the equity beta for the Covered Pipeline.

At least to the extent that the argument is framed by portfolio theory and the Sharpe-Lintner CAPM, paragraphs 213 and 214 of the Explanatory Statement are incorrect in their conclusion that downstream demand risk is diversifiable and should not be compensated in the rate of return. As we noted above, in the context of portfolio theory and the Sharpe-Lintner CAPM, the systematic risk of financial asset i can be measured as the product $\beta_i^2 \mathrm{var}(r_M)$. Neither βi nor the variance of the return on the market portfolio $\mathrm{var}\,(r_M)$ is directly driven by portfolio diversification. Indeed, neither portfolio theory nor the derivation of the Sharpe-Lintner CAPM assumes that investors diversify to the maximum extent possible. The portfolio theory principles from which the Sharpe-Lintner CAPM is derived assume a trade-off between risk and return so that equilibrium, for the individual investor and in the market for financial assets, is characterised not by the minimum variance of the individual's portfolio, or of the market portfolio, but by the trade-off between risk and return.

A beta for a financial asset which might otherwise be higher is not reduced because an individual investor has the opportunity to diversify away all part of the contribution which that asset makes to portfolio risk.

There is, then no reason to expect an estimate of the equity beta for the Covered Pipeline which in the range 0.50 to 0.70.

The gas transportation business based on the Covered Pipeline is not unlike the rail business of The Pilbara Infrastructure Pty Ltd:

(a) it has low prospects for diversification given its remote location and the associated economic base;[36]

(b) limited prospects for diversification, and a high dependence on the mining sector, expose it to the relatively high volatility of minerals markets; and[37]

(c) its major customers are in the mining sector and produce for export, indicating a potentially higher level of risk.[38]

The ERA recognised that the market circumstances of The Pilbara Infrastructure were not those of a railway providing general freight services, and were indicative of higher

36 Economic Regulation Authority, *Review of the method for estimating the Weighted Average Cost of Capital for the Freight and Urban Railway Networks, Draft Determination*, 5 June 2014, paragraph 117.

37 Ibid., paragraph 159.

38 Ibid., paragraph 428.

risk. Furthermore, this needed to be objectively established, but there were very few comparators among the Australian railway systems from which data might be obtained for beta estimation. Overseas comparators were considered, but the ERA was of the view that the remote location of The Pilbara Infrastructure railway, and its dependence on mineral exports, meant that an appropriate asset beta would be higher than an overseas general freight railway.[39] US based, Genesee & Wyoming Inc., which owns short line and regional freight railways in the United States, Canada, Australia, the Netherlands and Belgium, was chosen as the single relevant comparator. The ERA estimated an average asset beta for Genesee & Wyoming of 1.15.[40]

The similarity between the circumstances of The Pilbara Infrastructure and the GGP indicates that an estimate of the equity beta for the Covered Pipeline might well be outside the range 0.50 to 0.70 of the Rate of Return Guidelines, and above – possibly significantly above – 0.80. However, an apparent similarity of circumstances does not replace the requirement for a quantitative estimate of beta for application of the Sharpe-Lintner CAPM in estimation of the return on equity. One way of proceeding, would be to examine overseas comparators for the Covered Pipeline, but that is precluded by the Rate of Return Guidelines. Furthermore, the case of The Pilbara Infrastructure illustrates the problems of such an approach. Even if the sampling frame were extended, finding pipeline businesses which are similar to the business based on the Covered Pipeline, and which have traded shares, is likely to be difficult. The obvious candidates, North American pipeline businesses, supply gas into large and industrialised urban areas, and are often subsidiaries of larger energy businesses or of broader conglomerates. There are few, if any, North American comparators with traded shares from which data might be sourced to estimate an equity beta for the Covered Pipeline.

GGT has, therefore, sought advice from financial economists SFG on how an equity beta for the Covered Pipeline might be estimated using available and relevant Australian data. SFG's approach to beta estimation, and the results obtained, are outlined in the next section of the Supporting Information. SFG's report, *Cost of equity for the Goldfields Gas Pipeline: Report for GGT*, is provided as Attachment 7.

7.7.5 SFG estimation of the price of equity for the Covered Pipeline

Using absence of arbitrage methods to estimate an equity beta

The lack of comparators, for which long series of share price and dividend data can be obtained, makes difficult the estimation of beta using conventional statistical (regression) methods. Furthermore, even if suitable series were available for the Covered Pipeline, there is a substantial body of evidence showing that the application of regression methods leads to return on equity estimates which have little or no relationship with realised share prices.[41]

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39 Ibid.

40 Ibid., paragraph 461.

41 See SFG, *Cost of equity for the Goldfields Gas Pipeline: Report for GGT*, July 2014, paragraph 11. Some of the original research, and reviews of literature, are referred to in footnote 31 above.

Another approach must be taken, and financial economics offers a viable alternative with strong theoretical foundations, empirical support and extensive use in practice. Asset pricing can now proceed in ways other than through the use of equilibrium pricing models of which the Sharpe-Lintner CAPM is an early example. It can proceed through the very substantial body of theory developed, since the 1970s, which uses absence of arbitrage arguments to price financial assets (including complex financial assets which are difficult to price using models like the Sharpe-Lintner CAPM), and which has found extensive practical application in the pricing of derivative securities.[42]

Absence of arbitrage arguments can be used to price risky financial assets by transforming the uncertain cash flows from those assets into certainty equivalent cash flows, using risk neutral probabilities, and discounting those certainty equivalent cash flows at the risk free rate of return. Once an asset is priced in this way, the rate of return on investment in that asset is easily established. If the financial asset in question is equity, that rate of return can either be used directly as a required return on equity, or its implied equity beta can be ascertained and used in the Sharpe-Lintner CAPM to estimate the return on equity.

The method employed can be broadly described as follows. The objective is to estimate the discount rate – the return on equity – for equity investors, given estimates of returns available to investors in government debt and corporate debt issued on the same risky asset. The discount rate for equity can be determined by applying the same theory that is used to determine the price of call options and other derivatives.

Derivatives are priced by discounting certainty equivalent cash flows at the risk-free rate. In the case of derivatives, value is an outcome of the analysis of certainty-equivalent cash flows. In the case of the GGP, equity value is known (it is 40% of the asset base), but what is unknown is the discount rate for equity. In the case of the GGP, the discount rate for equity is an outcome of the analysis of certainty-equivalent cash flows. The approach is further explained in section A7.2 of the Appendix to this section of the Supporting Information.

Financial economists SFG have used this approach to valuation to estimate the price of equity for the Covered Pipeline. That price can be used to estimate the rate of return on equity for the pipeline, or the equity beta implied in the price can be estimated, and the beta can be used to indirectly estimate the return on equity using the Sharpe-Lintner CAPM. GGT has used the implied equity beta from SFG's work to estimate the return on equity of the Covered Pipeline, consistent with the approach of the Rate of Return Guidelines that the rate of return on equity be estimated using the Sharpe-Lintner CAPM.

In the paragraphs which follow, we summarise SFG's key assumptions, noting that they are consistent with the assumptions made by GGT elsewhere in determination of the proposed allowed rate of return. We then outline SFG's implementation of the

[42] Stephen Ross's Arbitrage Pricing Theory uses an absence of arbitrage argument (see Stephen A. Ross (1976), "The Arbitrage Theory of Capital Asset Pricing", Journal of Economic Theory, 13(3): pages 341-360). However, GGT is not proposing the use of Arbitrage Pricing Theory for estimation of the return on equity for the Covered Pipeline.

absence of arbitrage method, and note the results – the return on equity, and the implied equity beta. The details are in Attachment 7.

Estimates of key parameters

For estimation of the return on equity, SFG has made the following estimates of key parameters.

Risk free rate of return: 3.87%

SFG has estimated the risk free rate of return as an average of annualised yields to maturity on 10 year Commonwealth Government bonds using yield data, published by the Reserve Bank of Australia, for the 40 trading days to 10 June 2014.

SFG advises that estimation of the risk free rate from yields to maturity on five year Commonwealth Government bonds is inappropriate but examination of the reasons for this is beyond the scope its work for GGT. SFG notes that both the AER and IPART now use yields on 10 year bonds for estimation of the risk free rate.

GGT has set out the reasons why estimation of the risk free rate should use yields to maturity on 10 year Commonwealth Government bonds in section 7.6 above. GGT's estimate of the risk free rate, 3.73%, was made using yield data for the 40 trading days to 30 June 2014. SFG's estimate, which was made at an earlier date, is consistent with the estimate made by GGT.

Expected return on the market: 10.54%

SFG has used historical data over a long period, dividend discount analysis, and the views of independent experts, to estimate of the expected return on the market. Its estimate, without any adjustment for the value of imputation credits, is 10.54%.

Independently, GGT has made a similar estimate of the return on the market. GGT's estimate is 10.4% (without adjustment for the value of imputation credits). GGT's estimation of the expected return on the market is discussed in section 7.7.6 below.

Rate of return on debt: 6.23%

SFG's method of estimation of the return on equity for the Covered Pipeline requires, as an input, an estimate of the current return on debt for an entity of similar risk. SFG has estimated the return on debt to be 6.23%. SFG's estimate is a little higher than the "on-the-day" estimate of 6.16% which GGT reports below. The primary reasons for the difference are SFG's higher estimate of the risk free rate, and its higher (by 11 basis points) estimate of the debt risk premium. Both of these differences are a consequence of SFG making its estimates at dates earlier than the dates on which GGT has made similar estimates.

Benchmark gearing 60%, and BBB credit rating

SFG's estimate of gearing (60%), and its assumption about credit rating (BBB), are consistent with the proposals of the Rate of Return Guidelines, and with the assumptions which GGT has made for other aspects of rate of return determination.

Standard deviation of return on the market: 16.64%

SFG has used historical data over a long period (1883 to 2013) to estimate the standard deviation of the return on the market. Its estimate is 16.64%.

GGT does not require an estimate of standard deviation of the return on the market for other aspects of rate of return determination, and has not independently estimated this parameter.

SFG – Stage 1

SFG estimation of the price of equity for the GGP proceeds in two stages. In the first stage, SFG:

(a) estimates the market return in each of two states, designated "Good" and "Bad", so that the returns, the probabilities of the states and the risk neutral probabilities are consistent with an expected return on the market of 10.54%, market volatility of 16.64%, and a risk free rate of 3.87%;

(b) estimates payoffs to the asset and to debt holders in the "Good" state (a state with no default), in the "Bad" state with no default, and in the "Bad" state with default, so that the probabilities of default and the payoffs are consistent with the probabilities of the two states, with the yield to maturity on debt (6.23%), and with the assumed gearing (60%); and

(c) estimates the payoff to equity investors as residual claimants (who receive the difference between the payoff on the asset and the payoff to debt holders), and determines the average return on equity across the three scenarios ("Good", "Bad – without default", and "Bad – with default"), and the average return on equity across the without default scenarios, which is the return which must be used in total revenue and tariff calculations which assume no default (the assumption usually made when determining regulated access prices).

SFG concludes that the expected return on equity in the absence of default is 10.93%, and this implies an equity beta in the Sharpe-Lintner CAPM of 1.06. Once the risks of default are taken into account, the expected return to equity investors is 8.97%, and that this implies an equity beta of 0.77 in the Sharpe-Lintner CAPM.[43] However, this is not the beta required when using the Sharpe-Lintner CAPM to estimate the expected return on equity to be used in determining total revenue and regulated asset prices. Total revenue and regulated access prices are normally determined – and are determined by the ERA – in a model which does not take into account default. In

[43] If $10.93\% = 3.87\% + \beta \times (10.54\% - 3.87\%)$, then $\beta = 1.06$.

these circumstances, the appropriate cost of equity is 10.93%, and the corresponding Sharpe-Lintner CAPM equity beta is 1.06.

SFG carries out a number of sensitivity analyses on these results from the first stage of its estimation of the return on equity. These analyses indicate, among other things, a range for the equity beta of 0.81 to 1.32, which is consistent with the range 0.80 to 1.00 proposed by the ERA in May 2010. However, the range they indicate is not consistent with the range for beta, 0.50 to 0.70, proposed in the Rate of Return Guidelines. SFG concludes, in paragraph 123(c) of its report:

It is highly unlikely that setting the cost of equity capital equal to the five year government bond yield plus 0.7 x 6.00% would allow equity holders to earn a return commensurate with prevailing conditions in the market for funds. This understates the average return equity holders expect to earn in the absence of default and, in most sets of assumptions, even understates the expected return to equity holders across all situations.

The first stage in SFG's estimation of the price of equity for the GGP essentially demonstrates the way in which a binomial asset pricing model, incorporating the assumption of absence of arbitrage, can be applied to determination of the return on equity. Importantly, it shows how estimation can proceed using an approach that consistently applies estimates of financial parameters that are relevant and common to estimation of the return on equity and the return on debt (rule 87(5)(b)), and which has regard to interrelationships between estimates of parameters that are relevant to estimation of the return on equity and the return on debt (rule 87(5)(c)). We note, though, that in Stage 1 SFG does not estimate a return on equity for an entity with a degree of risk similar to that which applies to the service provider in respect of the provision of reference services.

In a second stage of estimation, SFG refines its Stage 1 estimation procedure, and calibrates its model so that the resulting return on equity is consistent with the risk of providing service using the GGP.

SFG – Stage 2

In the second stage of its estimation of the return on equity, SFG models possible movements, up and down, in the market return in each of the 60 months of the access arrangement period. This expands the binomial "tree" from two branches to 61 branches, and ensures greater precision in the resulting return on equity estimate.

The three steps of estimation in SFG – Stage 1 are repeated, but for the larger number of outcomes:

(a) the market return is estimated, not in two states ("Good" and "Bad"), but in 61 states which are classified into three groups designated "Good", "Most" (because it includes most market outcomes), and "Bad";

(b) payoffs to the asset and to debt holders are again estimated so that the probabilities of default and the payoffs are consistent with the probabilities of the states, with the yield to maturity on debt, and with the assumed gearing; and

(c) payoffs to equity investors as the residual claimants are estimated for each state, and the average return on equity is estimated across all scenarios, and across all without default scenarios, the return on equity across the without default scenarios being the return required as an input to total revenue and regulated tariff determination.

The classification of the 61 states into "Good", "Most" and "Bad" facilitates SFG's exposition of its method. The "Good" state spans all market outcomes with the top 8.50% of market returns, and the "Bad" state spans all of the market outcomes with the bottom 6.69% of market returns. The "Most" state spans the "middle" 84.81% of market returns.

As in SFG - Stage 1, the market returns in the each state, the probabilities of the states, and the risk neutral probabilities are determined in a way which ensures that they are consistent with the expected return on the market (10.54%), the market volatility, and the risk free rate (3.87%).

The market volatility assumed in Stage 2, 14.89%, is slightly lower than the volatility assumed for Stage 1 (16.64%). SFG explains that the lower volatility assumption results in one of the 61 possible market outcomes having a return of 10.54%, which is the average return on the market. This market outcome can, then, be regarded as the typical market outcome. This identification of one market outcome as the typical outcome facilitates exposition.

In the second step of estimation in Stage 2, SFG estimates payoffs to the asset and to debt holders for each market outcome. As in step 2 of Stage 1, these payoffs are determined so that the probabilities of default and the payoffs are consistent with the probabilities of the states, with the yield to maturity on debt (6.23%), and with the assumed gearing (60%).

With the much larger number of possible market outcomes, default cannot be limited to the "Bad" state. There is some probability of default in each of the "Good" and "Most" states. SFG has calculated the average default rates implied by its binomial model and has found:

(a) in the "Good" state (top 8.50% of market outcomes) the average default rate is 1.86%;

(b) in the "Most" state (middle 84.81% of market outcomes) the average default rate is 8.38%; and

(c) in the "Bad" state (bottom 6.69% of market outcomes) the average default rate is 35.66%.

The overall average default rate in the model is 9.65%. SFG advises that this is just below the average historical default rate over five years for Ba rated debt (9.72%), and higher than the average historical default rate for Baa rated debt (1.79%). However, the historical average default rates are not the default rates implied by the return on debt and the risk free rate of return of the model. They cannot be used. If the

historical average rates were to be imported into the pricing model, the internal consistency of the model's assumptions would be lost.

SFG assumes that the "Good" market outcomes (the top 8.50% of market outcomes) have payoffs on the asset of 115% of the typical market outcome, and that "Bad" market outcomes have payoffs on the asset which are 85% of the asset payoff in the typical market case. The asset payoff in the typical market case is the payoff obtained as that single value of asset return which equates the expected asset return across all market outcomes with the risk free rate, the expectation being calculated using the risk neutral probabilities. This value of asset return is 8.55% in the absence of default, and implies an asset return in a "Good" state of 11.63%, and a return of 5.08% in a "Bad" state. In the "Most" state, the asset return is between 5.08% and 11.63%.

The assumptions that "Good" market outcomes have payoffs on the asset of 115% of the typical market outcome, and that "Bad" market outcomes have payoffs on the asset which are 85% of the asset payoff in the typical market case, are important. It is through these assumptions that SFG calibrates its pricing model to the risk of providing service using the GGP.

SFG has used a version of GGT's total revenue and tariff model (tariff model) to examine the variation in asset returns to ascertain whether, in the specific circumstances of the GGP, those returns could, in the absence of default, be 85% to 115% of asset returns in the typical market case.

The rate of return estimates for the typical market case (risk free rate of return of 3.87%, return on debt of 6.23%, return on equity of 11.24% and return on the market of 10.54%) were used as baseline assumptions in the tariff model to examine the sensitivity of asset returns to changes in volume and contracted capacity. SFG concludes that the assumption of $\pm$ 15% variation in asset returns, as compared with the typical market case, is reasonable, justifying the use of 11.24% as the best estimate of the return on equity for the Covered Pipeline.

In the Stage 2 estimation, the returns to equity are, as they were for Stage 1, simply the differences between the asset payoffs and the payoffs to debt holders in each state, consistent with equity investors being the residual claimants. SFG finds:

(a) for the typical market case, in the absence of default, the return to equity investors is 11.69%, which implies an equity beta in the Sharpe-Lintner CAPM of 1.17;

(b) for the typical market case, with the possibility of default, the return to equity investors is 10.21%, which implies an equity beta in the Sharpe-Lintner CAPM of 0.95;

(c) across "Most" market outcomes, in the absence of default, the average return to equity investors is 11.0%, which implies an equity beta in the Sharpe-Lintner CAPM of 1.07

(d) across "Most" market outcomes, with the possibility of default, the average return to equity investors is 9.25%, which implies an equity beta in the Sharpe-Lintner CAPM of 0.81;

(e) across all market outcomes, in the absence of default, the average return to equity investors is 11.24%, which implies an equity beta in the Sharpe-Lintner CAPM of 1.10; and

(d) across all market outcomes, with the possibility of default, the average return to equity investors is 9.33%, which implies an equity beta in the Sharpe-Lintner CAPM of 0.82.

SFG reiterates (in paragraph 171 of its report) that regulated prices are typically set in a model which represents a single scenario incorporating a set of assumptions about volumes, capital expenditures, operating costs, payments to debt holders and taxation. A single scenario does not represent an expected, or probability weighted, view because it does not take into account for all possible outcomes. In particular, it does not take into account outcomes in which the service provider defaults. Total revenue and reference tariff determination proceed, not on the basis of expected outcomes, but in the context of a no default scenario.

In these circumstances, the relevant return on equity is a return in the absence of default. Sensitivity analyses carried out by SFG indicate that the expected return to equity investors in the absence of default is within the range 9.66% to 12.97%, implying an equity beta in the range 0.87 to 1.36.

SFG concludes that, for total revenue and reference tariff determination, the best estimate of the return on equity for a benchmark gas pipeline with similar risk to the GGP is 11.24%. This rate of return implies an equity beta of 1.10 in the Sharpe-Lintner CAPM.

GGT's estimate of the equity beta

GGT has used an estimate of 1.10 for the equity beta for estimation of the rate of return on equity used in determining the total revenue and reference tariff for the proposed revisions to the GGP Access Arrangement.

An estimate of the return on equity made by applying the Sharpe-Lintner CAPM with an estimate of the equity beta of 1.10, and with appropriate values for the other parameters of that model, will be an estimate commensurate with the efficient financing costs of a benchmark efficient entity with a degree of risk similar to that which applies to GGT in respect of its provision of the reference service using the Covered Pipeline.

We noted, in section 7.7.2 above, that estimation of the return on equity using the Sharpe Lintner CAPM requires, in addition to an estimate of the equity beta, estimates of the risk free rate of return and of the market risk premium. GGT's estimation of the risk free rate of return was discussed earlier, in section 7.6. In the following section we establish the estimate of the market risk premium.

7.7.6 Market risk premium

The Rate of Return Guidelines advise:

(a) historical averages of market risk premiums are relevant for informing the value of the market risk premium to be used in applying the Sharpe-Lintner CAPM (paragraph 128);

(b) the dividend growth model provides information that can be used to inform the choice of a value for the market risk premium (paragraph 128);

(c) given the range of relevant estimates available at the present time, a range of 5.0% to 7.5% is appropriate for the value of the market risk premium (paragraph 131);

(d) other relevant material is to be used to inform the selection of a point estimate from within the range (paragraph 130).

The market risk premium, the Explanatory Statement explains, is a forward looking concept subject to high levels of uncertainty in the short term. Any estimated market risk premium should be a forward looking premium commensurate with conditions expected to prevail during the regulatory period (Explanatory Statement, paragraph 698).

The range for the market risk premium is to be derived by combining information from historical time series data and from the dividend growth model (Explanatory Statement, paragraph 641). A point estimate is to be selected from within the identified range and, in establishing that point estimate, consideration is to be given to relevant information relating to investor perceptions of risk, and to prevailing financial market conditions (Explanatory Statement, paragraph 648).

Estimating the market risk premium when using the Sharpe-Lintner CAPM

In the Rate of Return Guidelines and the Explanatory Statement, the market risk premium is viewed as a long term average of differences between the return on the market and the risk free rate of return (estimated, in turn, from yields on Commonwealth Government bonds).

The use of historical data to estimate the market risk premium is explained in section 11.2.5 of the Explanatory Statement. Estimates of the historical market risk premium are made, the Explanatory Statement advises, by observing historical realised excess returns on the market (Explanatory Statement, paragraph 702). The rationale for this is that investors will determine the expected risk premium – the premium expected to prevail in the future, the forward looking risk premium – from realised equity returns in the past. This rationale relies on the assumption that expectations about the risk premium will be formed from observations made over a long period, and they will, therefore, be relatively stable over time. Investors are assumed not to change their

long term expectation of the historical market risk premium frequently as prices change daily in the market for financial assets.[44]

The evidence suggests, the Explanatory Statement indicates, that any estimate of the historical market risk premium is conservative, but using a historical market risk premium as one estimation method to determine a forward looking market risk premium is necessary, given that the return on equity and the forward looking market risk premium are not directly observable (Explanatory Statement, paragraph 712).

The market risk premium is, as the Explanatory Statement notes, a forward looking premium. In the context of the application of the Sharpe-Lintner CAPM, this forward looking risk premium must be constructed in a way which is consistent with the assumptions about investor expectations made for derivation of the model. If it is not constructed in this way, then the estimate of the return on equity which is obtained will not be an estimate made using the Sharpe-Lintner CAPM.

The use of a long term average of historical risk premiums to estimate the market risk premium of the Sharpe Lintner CAPM is incorrect.

Appendix 9 to the Explanatory Statement explains, and subsection A7.1 of the Appendix to this section of the Supporting Information articulates more clearly, that the Sharpe-Lintner CAPM can be derived from the precepts of portfolio theory. That theory describes the behaviour of a rational investor choosing, today, a portfolio of financial assets which will be used to transfer wealth to a point in time one period in the future. The assets available today, and from which the investor may choose in forming the portfolio, are:

(a) a set of risky financial assets for which the returns one period hence are not known with certainty, but for which the expected returns and variances of returns are known today; and

(b) a risk free asset which is known, today, to deliver a given return with certainty one period hence.

The market risk premium of the Sharpe-Lintner CAPM is the difference between:

(a) the expected return on the market portfolio of the risky financial assets available today, and for which expected returns and variances of returns one period hence are known today; and

(b) the risk free asset which is available to investors today.

In applying the Sharpe-Lintner CAPM, historical returns on the market might be used to estimate the return which an investment in the market portfolio today is expected to deliver one period hence.

[44] This is not an assumption which is required for derivation of the Sharpe-Lintner CAPM. Nor is it an assumption for which the Rate of Return Guidelines offer any justification based on economic principles or empirical evidence.

However, the return on the risk free asset must be a return at the time the model is applied. This – and not a long term average of past returns – is the return which investors, today, will take into account in their portfolio decisions.

If, as the Rate of Return Guidelines indicate, Commonwealth Government bonds are a suitable proxy for the risk free asset, then the yield on those bonds at the time the model is applied is the estimate of the risk free rate of return to be used in applying the Sharpe-Lintner CAPM to estimate a forward looking expected rate of return on equity.

In the Rate of Return Guidelines and the Explanatory Statement, estimation of the market risk premium is removed from the context of the Sharpe-Lintner CAPM. The conceptually correct current risk free rate of return in the model is replaced – incorrectly – by an average of the risk free rate over some prior period. The model of equity returns implied by this replacement of the current risk free rate with an average of historical risk free rates is not the Sharpe-Lintner CAPM. It is a model for which there is unlikely to be strong empirical support because it has no foundations in economic theory. As we noted earlier, in section 7.3, if a model without theoretical foundations and without strong empirical support is used in estimation of the rate of return, then there will be no reason to expect that the estimate obtained is commensurate with the efficient financing costs of the benchmark efficient entity of rule 87(3).

That the market risk premium of the Sharpe-Lintner CAPM is the difference between the expected return on the market portfolio and the return on risk free asset which is available to investors today does not mean that the long term average of the differences between the return on the market and the risk free rate is without interest. It is simply not relevant to the application of the Sharpe-Lintner CAPM.

The market risk premium, considered independently of the Sharpe-Lintner CAPM, has been, and continues to be, of great interest to economists since Mehra and Prescott showed that the persistent difference between the return on a US portfolio of equities (the S&P 500) and relatively risk free Treasury Bills was an order of magnitude greater than could be explained, using standard neoclassical economic theory, as a premium for bearing risk.[45]

The persistence of the premium, considered independently of the Sharpe-Lintner CAPM, as a long term average of differences between historical returns on the market and estimates of the historical risk free rate, provides a strong motivation for continued and substantial investment in risky financial assets and, in particular, for continued and substantial equity investments. It is the reason why researchers, like Dimson, Marsh and Staunton, have examined the premium over long periods of time and in many geographically dispersed financial markets.[46] In recent work, Dimson, Marsh and Staunton advise:

[45] Rajnish Mehra and Edward C Prescott (1985), "The Equity Premium: A Puzzle?", Journal of Monetary Economics, 15: 145-161.

[46] Elroy Dimson. Paul Marsh and Mike Staunton (2002), *The Triumph of the Optimists: 101 Years of Global Investment Returns*, Princeton: Princeton University Press.

In summary, there are good reasons to expect the equity premium to vary over time. Market volatility clearly fluctuates, and investors' risk aversion also varies over time. However, these effects are likely to be brief. Sharply lower (or higher) stock prices may have an impact on immediate returns, but the effect on long-term performance will be diluted. Moreover volatility does not usually stay at abnormally high levels for long, and investor sentiment is also mean reverting. For practical purposes, we conclude that for forecasting the long run equity premium, it is hard to improve on extrapolation from the longest history that is available at the time the forecast is being made.[47]

However, considering the market risk premium independently of the Sharpe-Lintner CAPM, when applying that model, as the Rate of Return Guidelines and the Explanatory Statement propose, leads to error. The market risk premium of the Sharpe-Lintner CAPM is not the persistent difference between the expected return on the market portfolio and the risk free rate of return, as might be measured by an average of historical risk premiums. Forecasts of this persistent difference – forecasts of the long run equity premium – may provide information potentially important to equity investors, but they are not relevant to the application of the Sharpe-Lintner CAPM.

The market risk premium of the Sharpe-Lintner CAPM is the difference between the expected return on the market portfolio and the risk free rate of return at the time the model is applied to estimate an expected rate of return on a financial asset.

If the Sharpe-Lintner CAPM is used, at a particular time, to estimate the expected return on equity, then the estimate of the risk free rate used in applying the model must be the estimate of the risk free rate prevailing at that time, and not an average of historical values. An average of historical values of the return on the risk free asset, which may be very different from the current value, will not provide the current estimate of the risk free rate which is required, in accordance with the underlying logic of the Sharpe-Lintner CAPM, to provide an estimate, at that time, of the expected of return on equity.

Identification of a proxy for the risk free asset, and estimation of the current rate of return on that asset has been discussed in section 7.6 above. In the paragraphs which follow we consider the estimation of the expected return on the market portfolio. We use historical data to directly estimate that expected return. We also examine estimates of that expected return obtained from dividend growth models.

Estimating the expected return on the market portfolio from historical data

The expected return on the market portfolio may be estimated as an average of historical returns measured using a market index. This average should be calculated for a long series of data, so that account is taken of the substantial variation in the returns on financial and other assets across the economic cycle. Brailsford, Handley and Maheswaran developed and published such a long series of Australian equity

[47] Elroy Dimson, Paul Marsh and Mike Staunton (2012), *Credit Suisse Global Investment Returns Sourcebook 2012*, page 37.

returns for 128 calendar years from January 1883 to December 2010.[48] These data show an average nominal rate of return of 11.8%.

GGT has calculated an average real rate of return from the data using the inflation series provided by Brailsford, Handley and Maheswaran, and has:

(a) converted that average real rate to a nominal rate using the Fisher equation and an inflation rate of 2.5% (the mid-point of the Reserve Bank of Australia target range); and

(b) adjusted the nominal rate for the value of imputation credits assuming those credits are valued at 0.25 (see section 8.6 below).

The result, 12.0%, is an estimate of the expected return on the market portfolio.

GGT notes that SFG has similarly used the Brailsford, Handley and Maheswaran data to estimate the expected return on the market portfolio for ATCO Gas Australia.[49] SFG has, however, extended the equity return series to 2012, and has adjusted the data for an inaccuracy in the calculation of dividend yields identified by NERA.[50] SFG's estimate of the expected return on the market portfolio is 11.6%.

GGT is of the view that data before 1960 should be used carefully when making quantitative estimates of the rate of return on the market portfolio:

(a) during the first half of the 20th century the Australian economy was still evolving from the primarily agrarian base which had developed during the 1800s;

(b) that evolution was punctuated by the major economic disruptions of the Great War, the Great Depression, and the Second World War;

(c) Australian financial markets were less developed in the first half of the 20th century; and

(d) the data themselves have to be constructed from a variety of sources, and are of variable quality.

Brailsford, Handley and Maheswaran discuss construction of the data for the period 1883 to 1957 in an earlier paper.[51]

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48 Tim Brailsford, John C. Handley and Krishnan Maheswaran (2012), "The historical equity risk premium in Australia: post-GFC and 128 years of data", Accounting and Finance, 52(1): pages 237-247.

49 SFG Consulting, *Estimating the required return on equity: Report for ATCO Gas Australia*, 13 March 2014, paragraph 196. Available at: http://www.erawa.com.au/infrastructure-access/gas-access/mid-west-and-south-west-gas-distribution-system/access-arrangements/2014-access-arrangement-proposal.

50 Brailsford, Handley and Maheswaran use a stock price index for the period 1875 to 1957 which was constructed by Lamberton. In a report for the Energy Networks Association in 2013, NERA identified, and corrected, an apparent error in Lamberton's yield data. See NERA Economic Consulting, *The Market, Size and Value Premiums, A Report for the Energy Networks Association*, June 2013. Available at: http://www.aer.gov.au/node/18859.

51 Tim Brailsford, John C. Handley and Krishnan Maheswaran (2008), "Re-examination of the historical equity risk premium in Australia", Accounting and Finance, 48(1): pages 73-79.

GGT has therefore estimated the return on the market portfolio from the Brailsford, Handley and Maheswaran data, but using only the data for the period of 50 years from 1961 to 2010. The shorter series excludes the effects of the major economic disruptions of the first half of the 20th century, but takes into account the substantial variation in the return on the market across multiple economic cycles. This variation can be seen from Figure 7.

Figure 7: Australian equity returns 1961-2010

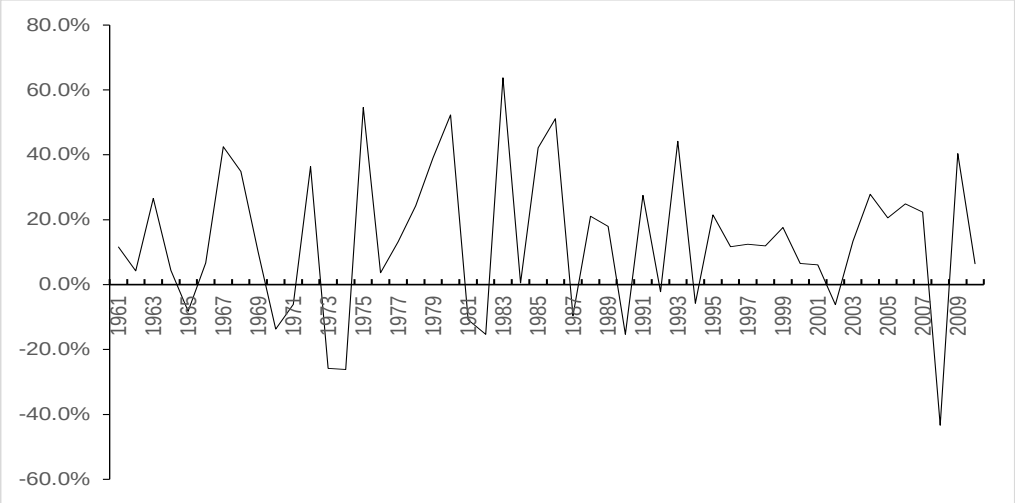

Figure 7 clearly shows the declines in equity returns which preceded the six recessions – in 1966, 1972, 1975, 1977, 1983 and 1991 – identified by Gillizter, Kearns and Richards.[52] It also shows the sharp drop in equity returns associated with the Global Financial Crisis in 2008.

The return on the market obtained using the Brailsford, Handley and Maheswaran data for the period 1961 to 2010, calculated from the source data as a real rate, converted to a nominal rate assuming inflation of 2.5%, is 10.25%.

These estimates of historical equity returns indicate to GGT that the expected return on the market portfolio may lie between 10.25% and 11.6%.

Estimating the expected return on the market portfolio using the dividend growth model

The Rate of Return Guidelines advise, at paragraph 128, that the dividend growth model provides information that can be used to inform the choice of a value for the market risk premium.

52 Christian Gillizter, Jonathan Kearns and Anthony Richards (2005), "The Australian Business Cycle: A Coincident Indicator Approach", paper presented at Reserve Bank of Australia Conference, *The Changing Nature of the Business Cycle*, 11-15 July 2005.
Available at: http://www.rba.gov.au/publications/confs/2005/index.html.

The dividend growth model provides an alternative to the use of historical data in the estimation of the expected return on the market portfolio.

The present value to an equity investor, today (time 0), of the future dividends from investment in one share of the stock of a firm which is not expected to fail, is:

$$PV_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n} + \cdots$$

where:

(a) D_i is the expected dividend on the share at time $t = i$, which is assumed to be paid at the end of year i; and

(b) k is the investor's discount rate, which is the required rate of return on equity.

If dividends are expected to grow at a constant annual rate g, the present value of the expected future dividends is:

$$PV_0 = \frac{D_1}{(1+k)} + \frac{D_1(1+g)}{(1+k)^2} + \cdots + \frac{D_1(1+g)^{n-1}}{(1+k)^n} + \cdots = \frac{D_1}{k-g}$$

provided $g < k$.

The price the investor would be prepared to pay for the share today (at time 0) is, then:

$$p_0 = \frac{D_1}{k-g}$$

Today's share price, p_0, is set in the market for financial assets, so that, given the expected dividend in one year, D_1, and the dividend growth rate, g, the investor's required rate of return – the expected rate of return on equity, k – is:

$$k = \frac{D_1}{p_0} + g$$

This is the simplest form of the dividend growth model.

Estimates of the expected return on the market portfolio made using a version of this model are provided in Appendix 15 of the Explanatory Statement. These estimates have been made:

(a) using dividend forecasts for the next two years obtained from the Bloomberg service;

(b) assuming future dividend growth at the rate of growth in GDP (assumed to be 3.0%), less a "dilution" adjustment for the net creation of shares; and

(c) adjusting for the value of imputation credits.

A further adjustment is made for a perceived bias in the dividend forecasts for the next two years.

If this perceived bias in dividend forecasts is removed, imputation credits are valued at 0.25, and real dividends are assumed to grow at 1.50%, the "average value return on equity (30/06/2006 to 31/08/2013)" reported in the Explanatory Statement is 8.60%. The Explanatory Statement reports an average value of the return on the market of 9.41% when no adjustment is made for bias in the dividend forecasts.

These estimates of the expected return on the market portfolio provided in the Explanatory Statement are different from estimates made using the dividend growth model and reported by others.

In March 2012, consultant economists CEG used a version of the dividend growth model similar to that described in the Explanatory Statement to estimate the expected return on the market for pipeline service providers Envestra, SP AusNet, MultiNet and APA Group. The estimate obtained was 12.3%.[53] CEG did not make a dilution adjustment for the net creation of shares, and did not make any adjustment for bias in the dividend forecasts which it obtained from the Bloomberg service.

CEG updated its work in November 2012, applying the dividend growth model in the same way as it applied the model in March, and reported a revised estimate of the expected return on the market of 11.9%.[54]

NERA also estimated the expected return on the market portfolio in work for Envestra, SP AusNet, Multinet and APA Group, applying the dividend growth model in a way similar to the way in which it was applied for the Explanatory Statement, and in which it was applied by CEG.[55] NERA examined the relationship between dividend per share growth and GDP growth, by regressing real dividend per share growth on real GDP growth and on real GDP growth lagged one year, and found a statistically significant positive contemporaneous relationship and a significant positive relationship at a lag of one year. No significant relationship was found between real dividend per share growth and real GDP growth at longer lags. However, although there were significant positive contemporaneous and one year lag relationships, about one half of the variation in real dividend per share growth could not be explained by real GDP growth. NERA concluded that the relationship between real dividend per share growth and real GDP growth made forecasting long run growth in dividends difficult and, instead, assumed that the expected long-run growth in real dividend per share was equal the past growth in real dividend per share of 3.07% per annum over the period 1981 to 2011.

Applying the dividend growth model using forecasts of dividend per share for the next two years obtained from the Bloomberg service and from the Institutional Brokers'

53 CEG, *Internal consistency of the risk free rate and MRP in the CAPM*, March 2012, page 48. Available at http://www.aer.gov.au/node/13556.

54 CEG, *Update to March 2012 Report: On Consistency of the Risk Free Rate and MRP in the CAPM*, November 2012, page 31. Available at http://www.aer.gov.au/node/13556.

55 NERA, *Prevailing Conditions and the Market Risk Premium: A Report for APA Group, Envestra, Multinet & SP AusNet*, March 2012.

Estimate System, assuming real growth in dividends of 3.07% and expected inflation of 2.5% per annum, NERA obtained an estimate of 11.7% for the expected return on the market.[56]

Capital Research reported on the expected return on the market for Aurora Energy in February 2012 and, in March 2012, updated its report (without making substantive changes in the estimates) for Envestra, SP AusNet, Multinet and APA Group. Capital Research reported an estimate of the expected return on the market of 13.3%, made using the dividend growth model and analysts' forecasts of dividend yields for the period these were available.[57] From earnings, dividends and cash flow data for 37 years across 22 markets, Capital Research estimated the average growth in (nominal) dividends to be 6.5%, and found that a rate of 7.0% was not unrealistic for Australia.

More recently, SFG used two versions of the dividend growth model to estimate the expected return on the market for the Energy Networks Association. The first version of the model was a constant growth perpetuity model of the type described above; the second version assumed that dividend growth would revert to a sustainable level over time. SFG estimated the return on the market over the period from July 2002 to December 2012 using analysts' forecasts of earnings per share, dividends per share and price targets obtained from the Institutional Brokers' Estimate System. Using the version of the model in which dividend growth reverted to a sustainable level, SFG obtained estimates of the expected return on the market of 10.6% for the period from 2002 to 2012, and 11.0% for the six months to December 2012. These estimates were not adjusted for the value attributed to imputation credits.[58]

If imputation credits were valued at 0.25, then the estimates of expected return on the market obtained by SFG would be 11.7% and 12.2%, respectively.

In May 2014, SFG reported estimates of the return on the market made using data from the second half of 2002 until mid-February 2014.[59] These data were partitioned into 24 periods each of six months. When adjusted for the value of imputation credits, assuming those credits are valued at 0.25, the average return on the market over the 24 periods was 11.7%, and the return for the most recent period was 11.4%. GGT has, through its relationship with APA Group, obtained, and is able to make use of, SFG's report. It is provided as Attachment 8 to the Supporting Information.

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56 Ibid., pages 38-39.

57 Capital Research, *Forward Estimate of the Market Risk Premium: An Update - A report prepared for the Victorian gas transmission and distribution businesses: APA Group, Envestra, Multinet Gas and SP AusNet*, March 2012, page 28. Available at http://www.aer.gov.au/node/13556.

58 SFG, *Dividend discount model estimates of the cost of equity*, 19 June 2013, pages 5-6.

59 SFG, *Alternative versions of the dividend discount model and the implied cost of equity: Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid*, 15 May 2014.

GGT notes that SFG's report was prepared for a number of energy network businesses, each of which has recently submitted, or is soon to submit, a revenue or access arrangement revision proposal to the AER. The report addresses a number of issues arising from the AER's Rate of Return Guideline, and parts of it are not directly relevant to GGT's proposed revisions to the GGP Access Arrangement. In particular, SFG's estimation of the market risk premium is neither relevant to, nor informative about, GGT's approach to estimating the market risk premium in the context of application of the Sharpe-Lintner CAPM. The energy network businesses which commissioned SFG's report did not ask SFG to inquire into the derivation of the Sharpe-Lintner CAPM, or into the implications of model derivation for the way in which the model is to be applied.

The estimates of expected return on the market discussed above are summarised in Table 19 (after adjustment for the value of imputation credits with γ = 0.25). The estimates shown in the table are not all of the estimates available; they are the estimates which have been made in the context of the publication of rate of return guidelines by the ERA and by the AER.

Table 19: Dividend growth model estimates of expected return on the market

	Date reported	Expected return
ERA (no bias adjustment)	August 2013	9.41%
ERA (adjusted for bias)	August 2013	8.60%
CEG	March 2012	12.3%
CEG	November 2012	11.9%
NERA	March 2012	11.7%
Capital Research	March 2012	13.3%
SFG (2002-2012)	December 2012	11.7%
SFG (six months to December 2012)	December 2012	12.2%
SFG	May 2014	11.7%
SFG (six months to February 2014)	May 2014	11.4%

GGT's estimate of the market risk premium

GGT has estimated the market risk premium as the difference between an estimate of expected return on the market portfolio and a current estimate of the risk free rate of return. This is the market risk premium required for application of the Sharpe-Lintner CAPM.

Historical data on equity returns indicate that the expected return on the market portfolio may lie between 11% and 12%.

Estimates made using the dividend growth model indicate that the expected return on the market portfolio may lie between 8.6% and 13.3%.

The lowest of the estimates made using the dividend growth model, 8.6%, is the estimate made by the ERA with adjustment of the GDP growth rate for the net creation of shares, and adjustment for a perceived bias in dividend forecasts obtained from the Bloomberg service.

Should the bias adjustment be made? Paragraph 13 of Appendix 15 to the Explanatory Statement advises that evidence exists to support the view that a systematic bias exists in analysts' forecasts of future dividends, and that there is evidence suggesting that economic forecasting has a poor performance record. Figure 14 of Appendix 9 shows a divergence between forecast dividends and observed dividends for the ASX 200 over the period from 2006 to 2014.

The evidence suggesting economic forecasting has a poor performance record is irrelevant. That evidence concerns the performance of sophisticated time series

models in forecasting changes in the macro economy.[60] It has no relevance to the way in which financial analysts forecast dividends, or to the results which might be obtained by those analysts.

Furthermore, as SFG has pointed out, the comparison between forecast dividends and actual dividends, showing divergence over the period of the Global Financial Crisis, a period of considerable uncertainty in markets for financial assets, does not indicate bias.[61] The results from applying the dividend growth model would be affected by bias in forecast dividends only if those forecasts were not incorporated into the current share price. The comparison which must be made to demonstrate bias affecting the results from applying the dividend growth model is between the analysts' dividend forecasts and the dividend stream that is reflected in the current stock price. This comparison is not made in Appendix 13 of the Explanatory Statement. The comparison, reported in the Appendix, of analysts' dividend forecasts and actual dividends, does not indicate bias for which an adjustment should be made when applying the dividend growth model.

Without the adjustment made for perceived bias in analysts' forecasts, the ERA's estimate of the expected return on the market is 9.41%. This estimate has been made assuming that dividends grow at about the rate at which GDP grows, less an adjustment for "dilution" associated with the net creation of shares.

In their applications of the dividend growth model, NERA, Capital Research and SFG do not make the assumption, commonly made, that dividends grow at about the rate at which GDP grows. NERA, as we noted above, examined the relationship between dividend growth and GDP growth and found that it was not sufficiently well defined to support its use in forecasting dividend growth. NERA, Capital Research and SFG all report estimates of the expected return on the market which are some 200 basis points higher than the ERA's estimate of 9.41%.

Use of the dividend growth model indicates an expected return on the market portfolio of between 11.4% and 13.3%. However, only one estimate made using the model exceeds 13.0%; the remainder are in the range 11.4% to 12.3%.

An estimate of the market risk premium should be a forward looking estimate commensurate with conditions expected to prevail during the regulatory period. The dividend growth model provides a forward looking estimate of the expected return on the market consistent the requirement for a forward looking estimate of the market risk premium. The estimates made using the dividend growth model indicate an expected return on the market which is somewhat higher than the return on the market obtained from historical data. The higher estimates might be explained by the dividend growth

60 Paragraph 13 of Appendix 13 specifically refers to studies by Robert Fildes and Spyros Makridakis (1995), "The impact of empirical accuracy studies on time series analysis and forecasting", International Statistical Review, 63(3): pages 289-308, and by David F. Hendry and Michael P. Clements (2003), "Economic forecasting: some lessons from recent research", Economic Modelling, 20(2): pages 301-329.

61 SFG, *Estimating the required return on equity: Report for ATCO Gas Australia*, 13 March 2014, pages 26-27.

models capturing the effects of gradual recovery from the Global Financial Crisis. Although higher, they are not, however, inconsistent with estimates in the range 11.0% to 12.0% obtained using historical data on equity returns.

GGT has, in these circumstances, taken a conservative view, and has used an estimate of 11.5% for the expected return on the market.[62]

With an estimate of the risk free rate of return of 3.73% (see section 7.6.4 above), GGT's estimate of the market risk premium to be used when applying the Sharpe-Lintner CAPM to estimate the rate of return on equity is 7.77%.

7.7.7 Estimation of the return on equity using the Sharpe-Lintner CAPM

GGT's estimates of the parameters of the Sharpe-Lintner CAPM are summarised in

Table 20: Parameters for estimation of the return on equity using the Sharpe-Lintner CAPM

Parameter		Estimate
Risk free rate of return	r_f	3.73%
Equity beta	β	1.10
Expected return on the market	$E(r_M)$	11.5%
Market risk premium	$E(r_M) - r_f$	7.77%

The rate of return on equity estimated from the parameter estimates in Table 20 is:

$$E(r) = r_f + \beta \times [E(r_M) - r_f] = 3.73\% + 1.10 \times 7.77\% = 12.28\%.$$

7.7.8 Cross checking the estimate of return on equity

The absence of comparators which can be shown to have a degree of risk similar to that of GGT in its provision of the reference service using the Covered Pipeline makes the task of cross checking the return on equity difficult.

The circumstances of the GGP being indicative of systematic risk higher than the systematic risks of Australian utility businesses with traded shares implies that the estimate of the return on equity for the Covered Pipeline should be higher than a comparable estimate of the return on equity for those businesses.

SFG has made an estimate of the return on equity for Australian listed energy networks businesses as part of its work on the dividend growth model for Jemena Gas Networks, Actew AGL, APA Group, Ergon, Networks New South Wales and Transgrid (Attachment 8 to the Supporting Information). SFG's estimate was 11.04%.[63] It was made assuming a risk free rate of return of 4.1%, and a return on the market of 10.3%.

62 This estimate assumes imputation credits are valued, with $\gamma = 0.25$. If no adjustment is made for the value of those credits, the estimate of the expected return on the market is 10.4%.

63 SFG, *Alternative versions of the dividend discount model and the implied cost of equity: Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid*, 15 May 2014, paragraphs 225-228.

The implied equity beta obtained using the Sharpe-Lintner CAPM was 0.94. This is consistent with a view of those businesses having lower systematic risk than the Covered Pipeline.

Using the estimates GGT has made for the risk free rate of return (3.73%) and the return on the market (11.5%), the corresponding estimate of the return on equity for the listed energy networks businesses is 11.0%. Again, this is consistent with a higher estimate of the return on equity for the Covered Pipeline (12.28%) with its higher systematic risk.

Although the Sharpe-Lintner CAPM has theoretical foundations, and this is one of the reasons why the model is endorsed by the Rate of Return Guidelines, we cannot ignore the fact that statistical analyses of the observed time series of asset returns provide little support for the model. In at least one respect this should not be surprising. As noted in Appendix 9 of the Explanatory Statement, and as we explain in subsection A7.1 of the Appendix to this section of the Supporting Information, the Sharpe-Lintner CAPM is obtained as an extension of portfolio theory. Portfolio theory is a theory of investor demand for financial assets with known distributions of uncertain future returns. Portfolio theory and, in consequence, the Sharpe-Lintner CAPM, do not explain the underlying economic processes generating returns on financial assets. Support for the model might, then, be difficult to find in observed series of asset returns.

Economic theoretical models which explain asset returns, and for which there is supporting empirical evidence, are proving elusive despite a very substantial research effort over the last 50 years. In the absence of tightly reasoned and tested deductive models, more inductive approaches to estimation of equity returns have become accepted and used in the last two decades. The best known of these approaches is the three factor model of Fama and French.[64] SFG has recently used the Fama-French model to estimate the return on equity for a benchmark energy networks business for ATCO Gas Australia.[65] When GGT's current estimates of the risk free rate of return and the expected return on the market are used in place of the earlier estimates made by SFG, the Fama-French model indicates a return on equity of 10.9%. The result is similar to the estimate of the return on equity for a listed networks business obtained using the dividend growth model (11.0%), and consistent with an estimate of 12.28% for the GGP with higher systematic risk.

7.7.9 Determination of the return on equity

In the preceding paragraphs of the Supporting Information, GGT has examined the Sharpe-Lintner CAPM and materials relevant to the estimation of its parameters. GGT has made estimates of those parameters in ways which are consistent with the theoretical construction of the Sharpe-Lintner CAPM, and has used the model to estimate the return on equity for the Covered Pipeline.

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64 Eugene F. Fama and Kenneth R. French (1992), "The Cross-Section of Expected Stock Returns", Journal of Finance, 47(2): pages 427-465.

65 SFG Consulting, *Estimating the required return on equity: Report for ATCO Gas Australia*, 13 March 2014, paragraphs 433-435. Available at: http://www.erawa.com.au/infrastructure-access/gas-access/mid-west-and-south-west-gas-distribution-system/access-arrangements/2014-access-arrangement-proposal.

As GGT has explained, the GGP serves mainly end users engaged in mining and minerals processing in remote areas of Western Australia, and who supply commodities into international markets. The risks of providing service using the GGP are, therefore, likely to be different from the risks of those listed Australian energy utilities for which equity betas are often estimated. If the share prices and dividends of those listed Australian Energy utilities were used to estimate the return on equity for the GGP, there would be no reason to expect that that return could contribute to achievement of an allowed rate of return commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to GGT in respect of the provision of the reference service using the Covered Pipeline.

Without relevant comparators, for which long series of share prices and dividends can be obtained for beta estimation using statistical (regression) methods, an alternative approach is required. With the assistance of SFG, GGT has used an absence of arbitrage method to estimate an equity beta for the Covered Pipeline, and has used that estimate to estimate the return on equity for the Covered Pipeline. Absence of arbitrage methods are now well established in financial economics. They have strong theoretical support and are widely applied, especially in the valuation of complex financial assets.

SFG's implementation of an absence of arbitrage method proceeds through the consistent application of the estimates of financial parameters that are relevant and common to estimation of the return on equity and the return on debt (rule 87(5)(b)), and has explicit regard to interrelationships between estimates of parameters that are relevant to estimation of the return on equity and the return on debt (rule 87(5)(c)). It is calibrated to the specific circumstances of service provision using the GGP, so that the estimate of beta obtained can be used with the Sharpe-Lintner CAPM to estimate a return on equity for the Covered Pipeline which contributes to the allowed rate of return objective of rule 87(3).

GGT's estimate of the return on equity is 12.28%. It is consistent with estimates made of the return on equity for listed Australian energy networks businesses using the dividend growth model and the three factor model of Fama and French.

GGT's proposed estimate of the expected return on equity for the Covered Pipeline is, then, 12.28%.

7.8 Estimating the return on debt

The benchmark efficient entity of the allowed rate of return objective of rule 87 is financed by equity and debt. The Rate of Return Guidelines require that return on the debt financing the benchmark efficient entity be estimated using an "on-the-day" approach. The on-the-day approach is one of three approaches to estimation of the return on debt identified (without limitation) in rule 87(10). The other two are:

(a) an approach that estimates the average return that would have been required by debt investors in the benchmark efficient entity if it had raised debt over a period prior to commencement of a regulatory year in the access arrangement period (trailing average approach); and

(b) a combination of on-the-day and trailing average approaches (hybrid approach).

In the subsections which follow, GGT describes its estimation of a return on debt using the on-the-day approach. The result does not satisfy the requirements of the NGL and the NGR, and GGT proposes an alternative estimate, made using a trailing average approach. The trailing average approach provides an estimate the return on debt which satisfies the requirements of the NGL and the NGR. That estimate, 7.89%, is used in determining the proposed allowed rate of return for the Covered Pipeline.

7.8.1 Return on debt in the Rate of Return Guidelines

Paragraph 370 of the Explanatory Statement advises that the on-the-day approach is preferred over the trailing average and hybrid approaches.

The on-the-day approach is to be implemented using a model (ERA return on debt model). This model is described in paragraph 70 of the Rate of Return Guidelines. It is:

$$r_d = r_f + DRP + DRC + HC,$$

where:

(a) r_d is the estimate of the rate of return on debt;

(b) r_f is the risk free rate of return;

(c) DRP is a debt risk premium;

(d) DRC is an allowance for debt raising costs; and

(e) HC is an allowance for hedging costs.

When using the ERA return on debt model to estimate the return on debt:

(a) the risk free rate of return is to be estimated as the average of observed yields on Commonwealth Government bonds with terms to maturity of five years over 40 trading days shortly before the start of the access arrangement period (Rate of Return Guidelines, paragraph 73); and

(b) the debt risk premium is to be estimated using the ERA's bond yield approach, with a joint weighting mechanism, applied to observed yields on relevant Australian corporate bonds (Rate of Return Guideline, paragraph 102).

In the bond yield approach, the debt risk premium is estimated as the average of the differences between the observed yield on each bond in a sample of relevant issues and the risk free rate with the same term maturity as the bond (Rate of Return Guideline, paragraph 103). The average used to estimate the debt risk premium is to be a weighted average of the differences calculated for each bond in the sample, with the weighting being the "joint weight". For each bond in the sample, this joint weight is to be the product of term to maturity of the bond and the amount at issue, divided by

the sum of the products of term to maturity and amount at issue for all bonds in the sample.

The sample of relevant bond issues is to be obtained from the Bloomberg data service, and the issues to be included in the sample are to be those for which:

(a) the credit rating is that of the benchmark efficient entity, as rated by Standard and Poor's;

(b) the remaining term to maturity is two years or longer;

(c) the bonds are issued in Australia, by Australian entities, and denominated in Australian dollars;

(d) the rate is either fixed or floating; and

(e) repayments may be bullets, or redemptions may be callable or puttable.

At least 10 yield observations are to be available over an averaging period of 40 days (Rate of Return Guidelines, paragraph 103).

The ERA return on debt model includes, in addition to the rate of return on debt which financial markets are expected to require (the sum of the risk free rate and the debt risk premium), a component of return which recovers debt raising costs, and a component which recovers hedging costs.

The direct costs of raising debt are, the Rate of Return Guidelines note:

(a) gross underwriting fees;

(b) legal and roadshow fees;

(c) company credit rating fees;

(d) registry fees; and

(e) paying fees.

An appropriate allowance for these costs would add 12.5 basis points to the benchmark efficient entity's annual cost of raising debt (Rate of Return Guidelines, paragraph 146).

In addition, the benchmark efficient firm can expect to incur costs of hedging its debt which adds a further 2.5 basis points to the rate return on debt if that return is to recover the return expected by financial markets and the costs of raising debt and managing a debt portfolio (Rate of Return Guideline, paragraph 147).

The return on debt and, in consequence, the allowed rate of return, are to be estimated for each year of the access arrangement period. The return on debt is to be updated annually for changes in the debt risk premium, with the risk free rate of return,

the allowance for debt raising costs and the allowance for hedging costs being held fixed at the estimates made as part of the ERA's final decision on a service provider's access arrangement revisions proposal (Rate of Return Guidelines, paragraph 71).

Annual updating of the return on debt is anticipated by rule 87(9)(b). If the return on debt is to be estimated in a way which accords with rule 87(9)(b), then the resulting change to the service provider's total revenue is to be effected automatically through the application of a formula which is to be specified in the regulator's decision on an access arrangement revision proposal (rule 87(12)).

Formulae for this purpose are proposed in paragraphs 79 to 81 of the Explanatory Statement. These formulae have the effect of annually adjusting the cost of debt in the service provider's total revenue for a given regulatory year by the change in the debt risk premium between the preceding year and that regulatory year.

7.8.2 ERA return on debt model

No rationale for the ERA return on debt model, in terms of economic principles and empirical evidence is provided in the Rate of Return Guidelines or the Explanatory Statement. Nor is any reason given for why the model might yield an estimate of the return on debt which can contribute to achievement of the allowed rate of return objective. The first of these issues – the rationale for the ERA return on debt model – is examined in the paragraphs which follow. A clear understanding of the model is required for its proper application.

In the ERA return on debt model, the return on debt is estimated by reference to the risk free rate of return. It is not estimated by reference to any prevailing interest rate. The return on debt could have been estimated by adding a margin to the swap rate for a swap with the same term to maturity as the debt for which the rate of return was being estimated. This was the approach taken in the work of the ERA's debt advisor, Chairmont Consulting. Chairmont Consulting advised:

As explained in more detail in Chairmont's report to the ERA in May 2013, the market usually looks at the 'margin' or 'debt risk premium' of corporate debt in relation to the swap rate, not the Commonwealth Government Securities (CGS) rate used in regulatory price setting terminology. Throughout this report, the DRP referred to is that over the swap rate of equal maturity, unless otherwise specified.[66]

However, the Rate of Return Guidelines make clear, in paragraph 70, that the ERA return on debt model estimates the return on debt as a margin over the risk free rate of return. The current yield on Commonwealth Government bonds of a particular term to maturity is to be used in the model, but as an estimate of the risk free rate.

The risk free rate of return is a theoretical construct. The use of this theoretical construct, and not a measure of the prevailing interest rate such as the swap rate, means that the core of the ERA return on debt model is a simple implementation of the Sharpe-Lintner CAPM.

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66 Chairmont Consulting, *Cost of Debt Comparative Analysis (For discussion at stakeholder workshop to be held on 7 November 2013)*, 5 November 2013, page 5.

The Sharpe-Lintner CAPM is a general model for the pricing of financial assets. Applying it in the estimation of the rate of return on debt:

$$E(r_{di}) = r_f + [E(r_M) - r_f] \times \beta_{di},$$

where

(a) $E(r_{di})$ is the expected rate of return on debt asset i; and

(b) $\beta_{di} = \text{cov}(r_{di}, r_M)/\text{var}(r_M)$ is the beta of debt asset i,

As before, r_f is the rate of return on a risk free asset, and $E(r_M)$ is the expected rate of return on the market portfolio.

Although, conceptually, debt can be priced using the Sharpe-Lintner CAPM, the facts that corporate debt (unlike equity) is infrequently traded, and that the data required for debt beta estimation are often not available, preclude direct application of the model.

In practice, the risk premium $[E(r_M) - r_f] \times \beta_{di}$ must be estimated, rather than the components of that premium ($E(r_M)$, r_f and β_{di}). This is the approach of the Rate of Return Guidelines. The expected rate of return on debt is estimated as the sum of the rate of return on the risk free asset and a premium for risk. Using the notation of paragraph 11 of Appendix 8 to the Explanatory Statement:

$$E_t(r_{i,\,t+1}) = r_{f,\,t} + DRP_t,$$

where

(a) $E_t(r_{i,\,t+1})$ is the time t expected return at time $t + 1$ on debt asset i;

(b) $r_{f,\,t}$ is the return on the a risk free asset at time t;

(c) DRP_t is the time t debt risk premium.

As the ERA noted in paragraph 316 of the Explanatory Statement, this model is widely used to estimate the return on debt.

7.8.3 Term to maturity and the debt risk premium

The Rate of Return Guidelines require that the premium for risk in the ERA return on debt model be estimated using the bond yield approach.

Risky debt has a term structure. Usually, the yield on debt with a longer term to maturity is higher than the yield on debt with a shorter term to maturity: the yield curve is upward sloping. The existence of a term structure with an upward sloping yield curve implies that the debt risk premium will increase with the term to maturity of the debt issued.

If, as the Rate of Return Guidelines require, an estimate of the return on debt is to be calculated using a debt risk premium, then a term to maturity of the debt for which the premium is to be estimated must first be specified.

In the application of the bond yield approach, in the way proposed in the Rate of Return Guidelines, the term to maturity is captured by estimating the premium from all debt issues in the relevant sample which have a remaining term to maturity of two years or longer. This overlooks the requirement of rule 87(8) for an estimate of the return on debt which contributes to achievement of the allowed rate of return objective. If estimation of the debt risk premium and application of the ERA cost of debt model are to lead to an estimate of the return on debt which contributes to achievement of the allowed rate of return objective, then the term to maturity of the debt from which the debt risk premium is estimated must be the term to maturity of the debt of the benchmark efficient entity. If it is not – if the term to maturity of the debt used to estimate the debt risk premium is arbitrarily chosen, as would be the case if the premium were estimated from debt issues which have a remaining term to maturity of two years or longer – then there is no reason to expect that the return on debt estimated using that premium would, except by chance, be an estimate which contributes to achievement of the allowed rate of return objective.

The requirement of the Rate of Return Guidelines to estimate the debt risk premium for all issues with remaining term to maturity of two years or longer has the effect of increasing the size of the sample used to estimate the premium. If the sample were from a homogeneous population, this would increase the reliability of the estimate obtained. But the sample appears not to be from a homogeneous population: the terms to maturity of the debt issues in the sample are not the same.

A further error arises from determination of the debt risk premium by reference to the remaining term to maturity of current debt issues. Use of the remaining term under-estimates the term to maturity of the debt issued and, assuming an upward sloping yield curve, imparts a downward bias to the estimate of the return on debt. Use of the remaining term to maturity may lead to an estimate of the return on debt trading in secondary markets, but such an estimate is not relevant for the pricing of the primary issues which service providers make to finance their investments in long-lived pipeline assets. The pricing of those primary issues is determined by, among other things, the terms to maturity of the issues.

If the service provider is to be given a reasonable opportunity to recover costs which are efficiently incurred in the provision of reference services (NGL, section 24(2)), then the term to maturity assumed for the debt of the benchmark efficient entity should be the term to maturity at issue, and not the remaining term to maturity.

GGT notes that, in its Rate of Return Guideline, the AER advises that for the purpose of estimating the return on debt, the term at issuance, rather than the remaining term to maturity, is required. The term at issuance reflects the premium associated with the original term length. An issuer has to pay this premium irrespective of the premium at a subsequent point in time, as reflected by the remaining term to maturity.[67]

[67] Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013, page 144.

The data which the ERA presented in Table 6 of the Explanatory Statement for the Draft Rate of Return Guidelines indicate that an efficient service provider is likely to issue debt with a term to maturity longer than 5 years and probably longer than 10 years.

The AER, for its Rate of Return Guideline, determined that the term to maturity of the debt issued by the benchmark efficient entity was 10 years. The AER concluded:

The determination of the benchmark debt term is a complex theoretical exercise. While we consider businesses will seek to issue longer-term debt, conceptually it is not clear what that term should be. Accordingly, we have considered the current debt financing practices of businesses considered to be close comparators to the benchmark efficient entity to inform us in arriving at a proposed debt term.

Based on observed practice we have assessed that the businesses' debt portfolio weighted average term at issuance is 8.7 years (ranging between 6.7 years to 16.3 years). We observe that businesses are securing bank debt with an average term at issuance of 4.3 years, issuing Australian bonds with an average term of 9.7 years and offshore bonds of 9.7 years. We understand that the current domestic bond market is not liquid in Australia beyond an issuance of seven years. However, businesses appear to be issuing offshore to cover any lack of liquidity in the domestic market. Further, when they issue offshore they appear to issue at multiple maturities (for example, seven, 10 and 15 years). We note that issuances beyond 15 years are currently not common.[68]

IPART has recently and similarly concluded that, for the purpose of estimating the return on debt of regulated businesses within its jurisdiction, the term to maturity of the debt issued should be assumed to be 10 years.[69]

In their consideration of the term to maturity, the AER and IPART have been guided by the practice of regulated businesses. They appear not to have been distracted by theoretical arguments which conclude that the term to maturity of the debt should be the length of the regulatory period. The practice of regulated businesses, now over a period exceeding 15 years, indicates that the theoretical arguments are deficient and require further development before they can inform regulatory decision making.

The AER, in the paragraphs we have quoted above, also notes the practice of regulated businesses of issuing debt in offshore markets to cover the lack of liquidity in the domestic financial market. This is consistent with the financing practices of Australian non-financial corporate entities in general. Since 2000, around three-quarters of the bonds issued by these entities were in offshore markets, principally the US bond market where investor demand for issues at longer maturities is strong.[70]

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68 Ibid., page 136.

69 Independent Pricing and Regulatory Tribunal, *Review of WACC Methodology, Final Report*, December 2013, page 11.

70 Ivailo Arsov, Matthew Brooks and Mitch Kosev, "New Measures of Australian Corporate Credit Spreads", Reserve Bank of Australia Bulletin, December Quarter 2013, pages 15-16.

Estimation of the debt risk premium in the way proposed in the Rate of Return Guidelines explicitly precludes consideration of this further aspect of debt financing and its implications for the return on debt. The Australian companies taken as comparators when determining regulated rates of return, all issue debt in offshore markets.[71] In these circumstances, the benchmark efficient entity is an entity which raises at least a part of its debt in offshore markets. To restrict estimation of the debt risk premium to bonds issued in Australia, by Australian entities, and denominated in Australian dollars, as proposed in the Rate of Return Guidelines, again leads to an estimate of the return on debt which cannot, except by chance, be an estimate which contributes to achievement of the allowed rate of return objective.

In summary, use of the bond yield approach, in the way proposed in the Rate of Return Guidelines, will not lead to an estimate of the return on debt which meets the requirements of rule 87 because:

(a) the term to maturity of the debt used to estimate the debt risk premium is arbitrarily chosen; it is not the term to maturity of the debt issued by the benchmark efficient entity; and

(b) no consideration is given to the issue of debt in offshore markets, when the benchmark efficient entity would be expected to issue at least a part of its debt in those markets.

In its estimation of the return on debt, GGT has assumed that the benchmark efficient entity of rule 87(3):

(a) issues debt with a term to maturity (at issue) of 10 years; and

(b) a part of the debt which it issues is issued in offshore markets.

An estimate of the debt risk premium which leads to an estimate of the return on debt which meets the requirements of rule 87 – an estimate for issues with term to maturity of 10 years, and taking into account the issue of debt in offshore markets – can be made using credit spreads now calculated and published by the Reserve Bank of Australia. We examine the Reserve Bank credit spreads, and use them to estimate the return on debt for the proposed revisions allowed rate of return for the Covered Pipeline. That estimate is presented in section 7.8.4.

7.8.4 GGT's estimate of the rate of return on debt

GGT has estimated a return on debt for the GGP using an on-the-day approach applying the ERA return on debt model. We find that the application of the on-the-day approach in the way indicated in the Rate of Return Guidelines does not, at the present time, satisfy the requirements of rule 87, nor does it yield a return on debt which contributes to achievement of the national gas objective. In the later part of this subsection of the Supporting Information we set out an alternative, trailing average, approach to estimation of the return on debt. The trailing average approach satisfies

[71] See, for example, Australian Energy Regulator, *Explanatory Statement: Rate of Return Guideline*, December 2013,Table 8.2, page 143.

the requirements of rule 87, and yields an estimate of the return on debt which contributes to achievement of the national gas objective. That estimate of the return on debt is used in determining the proposed allowed rate of return for the Covered Pipeline.

Using the on-the-day approach to estimation of the return on debt

An estimate of the risk free rate of return is required for estimation of the return on debt using the ERA return on debt model. As we noted earlier, in section 7.8.2, that model is a simple implementation of the Sharpe-Lintner CAPM. GGT has therefore used, as an estimate of the risk free rate of return in the ERA return on debt model, the estimate proposed in section 7.6.4 above. That estimate was 3.73%.

Since use of the bond yield approach, in the way proposed in the Rate of Return Guidelines, does not lead to an estimate of the return on debt which can meet the requirements of rule 87, GGT has examined an alternative approach using the corporate credit spreads now published by the Reserve Bank of Australia.

In December 2013, at the time the ERA issued its Rate of Return Guidelines, the Reserve Bank commenced publishing new measures of credit spreads for Australian non-financial corporate entities. The new measures are estimated monthly from a samples of issues which include bonds denominated in Australian dollars and in foreign currencies.

The samples of bond issues which the Reserve Bank uses to estimate credit spreads are restricted to fixed rate bonds issued by Australian non-financial corporations raising at least A$ 100 million, or the equivalent in United States Dollars or Euros. The samples include issues with embedded options at longer maturities (bullet bonds, callable bonds, convertible and puttable bonds). Bond price data are sourced from the Bloomberg BVAL service, and may be supplemented with Bloomberg generic price data or prices from UBS. Credit spreads on foreign currency issues are hedged into Australian dollar equivalent spreads (foreign currency risk is completely hedged). The spreads are measured relative to swap rates, and to rates on Commonwealth Government bonds.

The Reserve Bank has explained the method of estimation (relative to the swap rate) as follows:

(a) an aggregate credit spread is estimated for a given target tenor as the weighted average of the Australian dollar equivalent credit spreads over the swap rate for all bonds in the sample with the required credit rating; and

(b) the weights are determined by a Gaussian kernel that assigns a weight to every observation in the cross section depending on the distance of the observation's residual maturity from the target tenor according to a Gaussian (normal) distribution centred at the target tenor.[72]

[72] Ibid., page 20.

Paragraph 100 of the Rate of Return Guidelines advises: ". . . for the purpose of these guidelines, the benchmark credit rating is assumed to encompass the BBB-/BBB/BBB+ credit band". The Reserve Bank credit spreads are available for Australian non-financial corporations with BBB credit ratings. They are available for corporations with the credit rating assumed for the benchmark efficient entity.

The Reserve Bank credit spreads are available for bond issues by Australian non-financial corporations with term to maturity of 10 years. They are available for corporations with the term to maturity of debt assumed for the benchmark efficient entity.

At the time of the first issue of the credit spreads, the Reserve Bank advised:

The paucity of Australian dollar-denominated issuance by NFCs, particularly at longer tenors, makes it impractical to estimate credit curves across a range of tenors solely from domestically issued bonds. Therefore, the sample includes bonds denominated both in Australian dollars and foreign currencies.[73]

The Reserve Bank credit spreads are calculated for a sample which includes non-financial corporations which issue debt in offshore markets. As we noted above, the benchmark efficient entity is an entity which would not limit its debt raising to debt raising in the domestic financial market. The Reserve Bank credit spreads take into account the issue of debt in offshore markets.

The Reserve Bank credit spreads are available for non-financial corporations with BBB credit ratings, they are available for a term to maturity of 10 years, and they recognise that Australian non-financial corporations raise at least a part of their debt in offshore markets. The Reserve Bank credit spreads provide an alternative to the bond yield approach for estimation of the debt risk premium.

In a recent issues paper, the AER has acknowledged the relative transparency of the Reserve Bank credit spreads, but has expressed concern about the composition of the bond sample used to estimate those spreads.[74] The Reserve Bank does not provide a list of the specific bonds used in its sample, and this raises the possibility that the characteristics of the issuers may not closely match the characteristics of the benchmark efficient entity.

This is, indeed, a possibility, but it should be assessed against the alternative. In the way in which the bond yield approach is to be applied in accordance with the Rate of Return Guidelines, the list of bond issuers is made explicit, but there is no exclusion of financial corporations, with their very different requirements for debt raising, and there is no reason to expect that other issuers selected in accordance with the criteria of paragraph 103 of the guidelines would have the characteristics of the benchmark efficient entity of rule 87(3).

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73 Ivailo Arsov, Matthew Brooks and Mitch Kosev, "New Measures of Australian Corporate Credit Spreads", Reserve Bank of Australia Bulletin, December Quarter 2913, page 17.

74 Australian Energy Regulator, *Return on debt: Choice of third party data service provider – Issues Paper*, April 2014, sections 4.4.2 and 4.4.3.

The AER is also concerned that the Reserve Bank credits spreads are only available for the last day of a given month and, depending on the length of the proposed averaging period, this may lead to an estimate of the return on debt that reflects short term fluctuations.[75] Again, this is a possibility, but similar problems arise in applying the bond yield approach in accordance with the Rate of Return Guidelines. The Reserve Bank provides credit spread series, consistently estimated, from January 2005, which allows the user of those series to make an assessment of any anomaly in spreads reported for a particular month.

The Reserve Bank has noted that its use of a Gaussian kernel recognises the fact that the observed spreads on bonds with residual maturities close to the target tenor contain more information about the underlying spread at that term to maturity than spreads on bonds with residual maturities further way. The method uses the entire cross section of bonds to establish a weighting, albeit with weights approaching zero as the distance of the bond's residual maturity from the target term to maturity increases. In this respect, the weighting scheme used by the Reserve Bank to obtain its credit spreads is superior to simpler weighting schemes, such as the scheme used in application of the bond yield approach.

The Reserve Bank advises that its use of the Gaussian kernel provides a robust method for estimation of credit spreads, capable of producing estimates even when the number of observations is relatively small.[76] Furthermore, the credits spreads obtained are similar to the corresponding measures produced by the Bloomberg service prior to late 2008. After 2008, the Reserve Bank advises, its credit spreads diverge from the Bloomberg measures, particularly during the period 2009 to 2011 when the Bloomberg measures appear "counterintuitive".[77]

The Reserve Bank concludes that its new credit spread measures have a number of advantages over alternatives. These advantages are:

(a) the method of construction is more transparent;

(b) the sample is larger due to the inclusion of bonds issued in foreign currencies; and

(c) the method is relatively robust, allowing for the estimation of spreads at longer maturities than are available elsewhere.[78]

The AER is examining use of the Reserve Bank credits spreads in the estimation of the return on debt. IPART has advised that, from 1 July 2014, it intends to use the credit spreads in estimating the cost of debt.[79]

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75 Ibid., section 4.4.6.

76 Ivailo Arsov, Matthew Brooks and Mitch Kosev, "New Measures of Australian Corporate Credit Spreads", Reserve Bank of Australia Bulletin, December Quarter 2913, page 20.

77 Ibid., page 24.

78 Ibid.

79 IPART Pricing and Regulatory Tribunal, *New Approach to Estimating the Cost of Debt: Use of the RBA's Corporate Credit Spreads – Fact Sheet*, February 2014.

GGT has used the credit spreads calculated and published by the Reserve Bank of Australia to estimate the debt risk premium for the Covered Pipeline.

As the AER noted, the Reserve Bank credits spreads are only available for the last day of a given month and, depending on the length of the proposed averaging period, this may lead to an estimate of the return on debt that reflects short term fluctuations. GGT has therefore estimated the debt risk premium as the average of the credit spreads for bonds with BBB ratings and term to maturity of 10 years for the three months from April to June 2014.

GGT's estimate of the debt risk premium is 2.28%. Using the ERA cost of debt model with a risk free rate of 3.73% (and allowances for debt raising costs and hedging costs of 12.5 basis points and 2.5 basis points, respectively), the on-the-day estimate of the return on debt is 6.16% (= 3.73% + 2.28% + 0.125% + 0.025%).

Assessing the result obtained using the on-the-day approach

The Reserve Bank of Australia series of credit spreads for non-financial corporations commence in January 2005. The spreads relative to the returns on Commonwealth Government bonds for issuers with BBB ratings issuing bonds with a term to maturity of 10 years range from 0.92% to 9.31%, with the highest spreads in 2008 and 2009, following onset of the Global Financial Crisis.

This substantial variation in credit spreads indicates a substantial variation in the cost of debt over the decade since 2005.

In Table 21, GGT shows the return on debt, calculated year by year, using the Reserve Bank credit spreads in the ERA cost of debt model. The maximum return is the return calculated using the maximum value of the Reserve Bank credit spread for the year and the risk free rate estimated over the 40 trading days to the end of the month in which the maximum credit spread occurred. The minimum return is the return calculated using the minimum value of the credit spread for the year and the risk free rate estimated over the 40 trading days to the end of the month in which the minimum credit spread occurred. The average return shown in Table 21 is the average of the maximum and minimum returns.

Table 21: Estimated return on debt 2005-April 2014

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Maximum	6.62%	7.14%	8.53%	14.01%	11.71%	8.83%	8.19%	8.10%	7.60%	7.51%
Minimum	6.24%	6.45%	7.29%	8.56%	8.24%	8.12%	7.90%	6.61%	6.38%	5.98%
Average	6.43%	6.79%	7.91%	11.29%	9.97%	8.47%	8.04%	7.35%	6.99%	6.75%

If debt with a term to maturity of 10 year had been issued progressively, in equal annual amounts, at the averages of the minimum and maximum rates shown in Table 21, the average rate of return on debt would have been 8.00%. Even if debt had been issued progressively at the minimum rates shown in Table 21, the average rate of return on debt would have been 7.18%.

Use of an on-the-day approach to estimating the return on debt leads to a rate – 6.16% – which is significantly lower than an average rate of return over the last 10 years.

The opening capital base for the GGP, at 1 January 2015, is approximately $390 million. Assuming a gearing of 60% (see section 7.4 above), and using an on-the-day estimate of the return on debt of 6.16%, the annual cost of debt financing is some $14.4 million. Using an estimate of the return on debt of 7.18% – the average of the annual minimum rates over the last 10 years – the annual cost of debt would be around $16.8 million. The scheduling of debt issues, so that each subsequent new issue (10 years later) coincided with the occurrence of the minimum rate of return in the year of issue, would, however, be difficult to achieve. The annual cost of debt would be above $16.8 million.

Adoption of an on-the-day approach to estimation of the return on debt for the GGP will lead to a cost of debt which is at least $2.4 million per year, or around 12%, lower than the cost debt which an efficient service provider, with an asset base of around $390 million and gearing of 60%, would be likely to incur.

The Explanatory Statement advises that an on-the-day approach to estimation of the return on debt is superior to the alternatives in terms of productive efficiency, and in terms of allocative efficiency (paragraph 345). This may, or may not, be the case. The rate of return on debt is the price the regulated firm is expected to pay for debt. It is not the regulated firm's cost of debt; nor is it the price the regulated firm charges for the services it provides. If the firm in question is the benchmark efficient entity, there may be a case for presuming productive efficiency. Allocative efficiency is, however, a matter of the costs from which the prices to be charged by the regulated firm have been determined, and the structures of those prices (they are likely to be multi-part prices, and not simple prices equated to marginal costs). Neither the Explanatory Statement, nor Appendix 3, provides reasons for presuming that an on-the-day estimate of the return on debt will result in prices which lead to allocative efficiency.

Furthermore, any reason for presuming that an on-the-day approach to estimation of the return on debt will lead to allocative efficiency is overturned by the proposed partial annual updating of the Rate of Return Guidelines.

Annual updating of the return on debt *might* lead to allocative efficiency, to the extent that reference tariffs better reflect the forward looking cost of investing in capacity, and correctly signal the of the opportunity cost of using gas. However, the Rate of Return Guidelines advise that it is the risk free rate which drives much of the variation over time observed in the return on debt; the debt risk premium is not expected to change significantly under usual circumstances (paragraph 85). Allocative efficiency arguments might justify an on-the-day approach to the return on debt, but that justification is lost by proposed annual updating which ignores the principal cause of the variation in the return on debt – variation in the estimate of the risk free rate. For four out of five years of an access arrangement period, a return on debt estimated using an on-the-day approach and annually updated by updating only the debt risk premium will not better reflect the forward looking cost of investing in capacity, and will have the potential to lead to allocative efficiency only by chance.

The proposed annual updating of the return on debt is a consequence of weight being given to tariff stability in assessing the long term interests of consumers (Rate of Return Guidelines, paragraph 84). GGT does not know whether tariff stability is in the long term interests of consumers of natural gas, and neither the Rate of Return Guidelines, nor the Explanatory Statement, provide much evidence on whether this is the case. They appear to rely on the views of retailers, which may or may not be the views of final consumers.

Nevertheless, in proposing annual updating of the debt risk premium, and not of the other components of the estimate of the return on debt, the Rate of Return Guidelines abandons allocative efficiency in favour of price stability being in the long term interests of consumers.

This is not necessarily inconsistent with the requirements of the national gas objective.

The Expert Panel which reviewed the limited merits review regime of the NGL (and the National Electricity Law) was clear that the promotion of the long term interests of consumers did not mean the promotion of economic efficiency alone:

One view put forward is that the NEO and NGO are focused on the promotion of economic efficiency, and that the reference to the long-term interests of consumers simply indicates that the expected effect of promoting efficiency is that it will simultaneously promote the long-term interests of consumers. The Panel has rejected this view because there are multiple definitions of the concept of efficiency and, at least in relation to the definitions and measurements usually adopted for practical policymaking purposes; it is not the case that higher efficiency necessarily promotes the long-term interests of consumers.[80]

The Expert Panel also drew attention to the fact that the national gas objective refers specifically to the *long term* interests of consumers of natural gas (and not just to the interests of those consumers). This, the Panel explained, was to mitigate the risk of excessive weight being given to today's consumers at the expense of future consumers. The promotion of long term consumer interests was achieved by:

(a) limiting the scope for decision making to the promotion of improvements in a number of explicitly identified dimensions of efficiency (efficiency in investment, efficiency in operations, and efficiency in use), and

(b) putting investment efficiency at the front of the short list of means of efficiency improvement.[81]

If this broader view of the national gas objective is taken, then a failure to adequately finance efficient pipeline operations through the setting of reference tariffs, and a failure to motivate, via those tariffs, future efficient investment in reference services, are not in the long term interests of the consumers of natural gas.

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80 Professor George Yarrow, The Hon Michael Egan, and Dr John Tamblyn, *Review of the Limited Merits Review Regime: Stage Two Report*, 30 September 2012, page 26.

81 Ibid.

Moreover, if this broader view is taken, then there is no issue of inconsistency between the national gas objective and the revenue and pricing principles of the NGL.

In exercising its economic regulatory powers, the regulator must exercise those powers in a manner that is likely to contribute to achievement of the national gas objective (NGL, s. 26(1)). The regulator must also take into account the revenue and pricing principles when exercising a discretion in approving or making those parts of an access arrangement relating to a reference tariff (NGL, s. 28(2)). The revenue and pricing principles require that a service provider be provided with a reasonable opportunity to recover at least the efficient financing costs incurred in providing reference services (NGL, s. 24(2)). They also require (NGL, s. 24(3)) that the service provider be provided with effective incentives to promote:

(a) efficient investment in the pipeline used to provide reference services;

(b) efficient provision of pipeline services; and

(c) efficient use of the pipeline

If the national gas objective were to be interpreted as referring only to economic efficiency – in particular, to the productive and allocative dimensions of economic efficiency – then there would be the potential for inconsistency between the objective and the requirement that the service provider be provided with an opportunity to recover at least its efficient costs.

This would be the case, as we have shown above, when an on-the-day approach is used to estimate the return on debt for the GGP. The estimates of return on debt shown in Table 21 above clearly indicate that, if the on-the-day estimate of 6.16% were used to determine the proposed revised reference tariff for the GGP, the tariff would not provide GGT with an opportunity to recover its efficiently incurred costs.

An on-the-day approach to estimation of the return on debt may lead to reference tariffs which better reflect the forward-looking cost of investing in pipeline capacity, and which signal to gas consumers the transmission component of the opportunity cost of gas use. That may be in the interests of consumers. But if the reference tariffs are insufficient to provide the service provider with the opportunity to recover its efficiently incurred costs of providing reference services, they will impair the continued and efficient provision of pipeline services, and they will not motivate a service provider's future efficient investment in the pipeline used for reference service provision. Adoption of an on-the-day approach to estimation of the return on debt will not, in these circumstances, be in the long term interests of consumers of natural gas, and will not contribute to achievement of the national gas objective.

GGT's estimate of the return on debt for the Covered Pipeline

GGT has therefore adopted a trailing average approach to estimation of the return on debt for the Covered Pipeline.

The length of the trailing average is 10 years, matching the average term to maturity of debt which would be issued by the benchmark efficient entity of rule 87(3). The same

weight is applied to each term in the average, as would be the case if one tenth of the benchmark efficient entity's debt were refinanced each year.

Each term of the trailing average is calculated using the ERA return on debt model with:

(a) the debt risk premium calculated as the average of the credit spreads on the bonds of non-financial corporations, with credit ratings in the BBB band, and term to maturity of 10 years, as reported by the Reserve Bank of Australia, for the three months from April to June in the year for which the term of the trailing average is calculated;

(b) the risk free rate calculated as the average of the yields on Commonwealth Government bonds with terms to maturity of 10 years, as published by the Reserve Bank of Australia, for the 40 trading days preceding 30 June in the year for which the term of the trailing average is calculated;

(c) allowances for debt raising and hedging costs of 0.125% and 0.025%, respectively, in the year for which the term of the trailing average is calculated.

GGT has assumed, but has not incorporated into its return on debt estimation, that the trailing average will be updated annually during the access arrangement period. The first update will take place immediately prior to the commencement of second regulatory year in the access arrangement period, and subsequent updates will take place at approximately 12 month intervals after that first update.

When the trailing average estimate of the return on debt is updated, the earliest estimate will be dropped from the average, and an estimate for the current year will be added.

The calculation of the trailing average commences in 2014, using the Reserve Bank of Australia credit spreads for the period from January 2005.

GGT's estimate of the return on debt for the first year of the access arrangement period, obtained using the trailing average approach, is 7.89%. The calculation is shown in Table 22.

Table 22: Estimation of the return on debt for the Covered Pipeline

Reserve Bank of Australia credit spreads
BBB rated securities
Spread to Commonwealth Government bonds
Term to maturity 10 years

	Jan	Feb	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	100.684	94.923	100.407	100.987	96.205	92.017	92.517	102.346	101.732	105.238	104.063
2006	100.059	102.311	125.549	122.599	125.160	127.921	129.747	110.103	135.226	117.403	113.583
2007	258.831	166.859	123.925	122.217	133.836	160.766	168.161	177.718	182.574	201.309	223.650
2008	227.348	276.644	294.352	262.353	325.949	304.851	307.736	363.749	575.306	827.377	931.082
2009	741.903	598.854	643.969	473.995	430.395	348.105	344.619	342.652	339.409	338.274	261.789
2010	284.756	267.671	225.551	305.210	288.939	258.392	249.316	259.146	249.205	243.884	237.953
2011	231.242	224.150	260.110	246.188	272.727	284.533	330.460	347.131	368.335	388.401	409.848
2012	413.637	395.071	371.113	385.433	406.793	383.938	379.516	361.312	331.140	346.500	330.409
2013	317.210	326.981	325.733	300.726	348.786	333.474	340.263	351.399	324.425	321.766	325.238
2014	314.602	292.144	241.800	233.310	209.990						

Trailing average estimate of return on debt: average credit spread February, March, April

Risk free rate	5.56%	5.44%	5.81%	6.13%	4.42%	5.71%	5.47%	4.02%	3.38%	4.07%
Debt risk premium	0.98%	1.09%	1.40%	2.96%	6.46%	2.40%	2.36%	3.78%	3.25%	2.70%
Allowance for debt raising costs	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%	0.1250%
Allowance for hedging costs	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%	0.0250%
Return	6.69%	6.68%	7.36%	9.24%	11.03%	8.26%	7.98%	7.95%	6.78%	6.92%

Return on debt: trailing average estimate: average credit spread February, March, April **7.89%**

GGT's use of the trailing average approach does not accord with the proposals of the Rate of Return Guidelines but, as we explained above, the proposal of the Guidelines cannot deliver a rate of return on debt which contributes to achievement of the allowed rate of return objective of rule 87. Use of a trailing average approach is, however, admissible under rule 87(10)(b) (and is the approach proposed in the AER's Rate of Return Guideline). GGT has applied the trailing average approach using the ERA return on debt model with:

(a) an estimate of the risk free rate of return which is consistent with the core of that model being a simple implementation of the Sharpe-Lintner CAPM, which the Rate of Return Guidelines identifies as a relevant model for informing estimation of the allowed rate of return of rule 87; and

(b) a debt risk premium calculated for an issuer with a credit rating in the BBB band, and for debt of term to maturity of 10 years, which are the credit rating and term to maturity for the benchmark efficient entity of rule 87(3);

That is, GGT has adopted a method for estimation of the return on debt, and has obtained an estimate using that method, which can be expected to contribute to achievement of the allowed rate of return objective.

Furthermore, use of a trailing average approach yields a return on debt which should provide GGT with the opportunity to recover its efficiently incurred costs of providing the reference service using the Covered Pipeline. The ability to recover its efficiently incurred costs provides, in turn, incentives for GGT's further efficient investment in the Covered Pipeline, and for its efficient provision of pipeline services. This is in the long term interests of consumers of natural gas, and will contribute to achievement of the national gas objective.

7.9 Proposed allowed rate of return

The allowed rate of return is to be a weighted average of the return on equity for the access arrangement period, and the return on debt, which is to be determined on a nominal vanilla basis (rule 87(4)).

GGT has assumed (section 7.4 above) a gearing of 60% for the benchmark efficiency entity of the allowed rate of return objective.

The return on equity has been estimated as the return required by equity investors investing in a benchmark efficient entity which has a similar degree of risk as that which applies to GGT in respect of the provision of the reference service using the Covered Pipeline. That estimate of the return on equity is 12.28%.

The return on debt has been estimated as the average return that would have been required by debt investors in the benchmark efficient entity if it had raised debt over the 10 years prior to commencement of the access arrangement period. That estimate of the return on debt is 7.89%.

The nominal vanilla weighted average of these estimates of return on equity and return on debt, assuming a gearing of 60%, is 9.64%.

GGT's proposed allowed rate of return for revision of the GGP Access Arrangement is 9.64%.

Appendix: Asset Pricing

As we noted in section 7.7.1 above, the Sharpe-Lintner CAPM is not referred to in rule 87 of the NGR. Empirical analysis does not provide much support for the model, and its use, as recommended by the Rate of Return Guidelines, is guided largely by economic principles.

In this Appendix, we set out the economic principles from which the Sharpe-Lintner CAPM is derived with a view to ensuring that our application of the model is in the way intended in the Rate of Return Guidelines, and is consistent with the relevant underlying economic theory.

A second section of the Appendix briefly summarises the economic principles supporting the absence of arbitrage approach to asset pricing. GGT has relied on an absence of arbitrage approach to estimate the equity beta for the GGP.

A7.1 Portfolio theory and the Sharpe-Lintner CAPM

Portfolio theory, Appendix 9 of the Explanatory Statement explains, addresses the question of how a rational investor best allocates the wealth he or she has available for investment among the assets on offer in the market for financial assets.

Portfolio theory is not, however, a theory of market equilibrium. Portfolio theory must be augmented if an explanation is to be provided of the prices at which financial assets trade or, equivalently, of the rates of return on those assets.[82]

When all investors make their portfolio decisions using portfolio theory, and certain additional assumptions are made about the market for financial assets and about investor behaviour in that market, market equilibrium is characterised by a simple linear relationship between the expected rates of return on risky assets and the relative riskiness of those assets. This simple linear relationship is the Sharpe-Lintner CAPM.

In the paragraphs which follow, we carefully articulate the links from portfolio theory to the Sharpe-Lintner CAPM. This is necessary for proper application of the model.

Portfolio theory

The "set up" for portfolio theory is described in paragraph 2 of Appendix 9. We expand on that description in this section of the Supporting Information, drawing on presentations in two of the standard textbooks on financial economics.[83]

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82 If a financial asset – equity or debt - is purchased today for a price p_t, and that asset provides the investor, one period later, with a payoff, Y_{t+1}, from the cash flows of the entity which has issued the asset, then the investor's anticipated rate of return at the time the asset is purchased, r_t, is:

$$r_t = \frac{Y_{t+1} - p_t}{p_t} = \frac{Y_{t+1}}{p_t} - 1.$$

This one period example, which can be generalised, shows that rates of return are inversely related to the prices which are paid for financial assets. In consequence, the terms "rate of return determination" and "asset pricing" are used interchangeably.

At a point in time (time 0), an investor makes a decision to consume from her wealth, and to invest the remainder of that wealth in financial assets. One period later (at time 1), the investor sells those financial assets to buy goods and services.[84] That is, at time 0, the investor makes a decision to form a portfolio of financial assets for the purpose of transferring wealth to time 1 to finance future consumption.

As described in Appendix 9 to the Explanatory Statement, portfolio theory assumes that the investor's preferences for portfolios of financial assets can be represented by a utility function defined over the portfolio mean or expected return, and the variance of portfolio returns.[85] This utility function, $V(E(r_p), var(r_p))$, represents the investor's preference for portfolios with higher expected returns $E(r_p)$, and for portfolios with lower variance of returns, $var(r_p)$: investor utility increases with increasing portfolio expected return, and decreases with increasing variance of returns.

As Appendix 9 notes, variance is a measure of the divergence of realised returns from the expected return on a portfolio of financial assets. It may therefore be interpreted as a measure of risk. With this interpretation, the investor's utility function V represents a trade-off between expected return and risk. A rational investor will choose a portfolio which minimises returns variance, or risk, for a given level of expected return. Moreover, for any given level of returns variance, or risk, the investor will choose the portfolio with the highest expected return.

N risky financial assets are assumed to be on offer to the investor at time 0. These assets are indexed by $i = 1, 2, \ldots, N$.

Each of these assets provides the investor with a payoff, at time 1, from the cash flows of the entity which has issued the asset. Different circumstances over which the investor has no control (contingent states), are possible during the period of the investment (between time 0 and time 1), and lead to different possible payoffs on each financial asset. The payoffs, then, are not known to the investor at time 0. They are random variables at that time. Provided each asset has a non-zero price at time 0, the rates of return which the investor can earn on the assets are also random variables. r_i will denote the random rate of return on financial asset i.

The presentation of portfolio theory, and the derivation of the Sharpe-Lintner CAPM, are often simplified by referring to the total, or gross, return on financial asset i, rather than the rate of return on that asset. The total return on an asset i with rate of return r_i is $R_i = 1 + r_i$.

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83 Chi-fu Huang and Robert H Litzenberger (1988), *Foundations for Financial Economics*, New York: Elsevier; and Jonathan E Ingersoll (1987), *Theory of Financial Decision Making*, Savage, Maryland: Rowman and Littlefield.

84 In a multi-period setting, the investor would also buy financial assets for the next period. The Sharpe-Lintner CAPM is not, however, a multi-period asset pricing model and, as in Appendix 9 of the Explanatory Statement, we do not extend beyond a single period. We note that most recent asset pricing research uses a multi-period or continuous time setting for the purpose of overcoming the inherent limitations of a single period model.

85 There has been much debate about the appropriateness of defining preferences over portfolio expected returns and return variances, rather than over consumption goods which is the standard view in contemporary microeconomics. Defining preferences over portfolio expected returns and return variances may have validity when the probability distribution of returns is a two parameter distribution, or when the utility function is quadratic.

Let W_0 be the remainder of the investor's wealth at time 0, after her decision to consume at that time. If the investor invests W_0 in a portfolio of the risky financial assets on offer at time 0, her wealth one period later, at time 1, is:

$$W_1 = W_0 \sum_{i=1}^{N} w_i R_i,$$

where w_i is the fraction of W_0 invested in asset i: $w_i = p_{i0}X_{i0}/W_0$, p_{i0} is the (known) price of asset i at time 0, and X_{i0} is the number of units (shares) of asset i which the investor purchases at that time.

The wealth which the investor has available to invest at time 0 is, of course, known to the investor at that time, but the investor does not know, at that time, what her wealth will be one period later. W_1 is a random variable because it is a linear combination of the random total rates of return, R_i, on the risky financial assets on offer at time 0.

Given the form of her utility function, the investor seeks to choose a portfolio of risky financial assets to minimise portfolio return variance subject to achieving a specified expected total return, $E^*(R_p)$, and subject to satisfying the "budget constraint" that the total of the amounts invested in the assets is equal the wealth available for investment. The investor is concerned with choosing the set of portfolio weights w_i, $i = 1, 2, \ldots, N$, which minimises

$$\mathrm{var}(R_p) = \sum_{i=1}^{N}\sum_{j=1}^{N} w_i w_j \,\mathrm{cov}(R_i, R_j) \qquad (1)$$

subject to

$$\sum_{i=1}^{N} w_i E(R_i) = E^*(R_p) \qquad (2)$$

and

$$\sum_{i=1}^{N} w_i = 1 \qquad (3)$$

GGT's equation (1) above is equation 19 of paragraph 3 of Appendix 9 of the Explanatory Statement. The portfolio variance to be minimised is equivalent to the portfolio variance in equation 19 of paragraph 5 of Appendix 9. (In equation 19, the covariances, $\mathrm{cov}(R_i, R_j)$, of GGT's equation (1) are represented, equivalently, as the products, $\rho_{ij}\sigma_i\sigma_j$, of the correlation coefficients ρ_{ij} and the standard deviations σ_i and σ_j).

We note that w_i can be positive or negative: the investor can hold a long or a short position in any of the financial assets on offer.

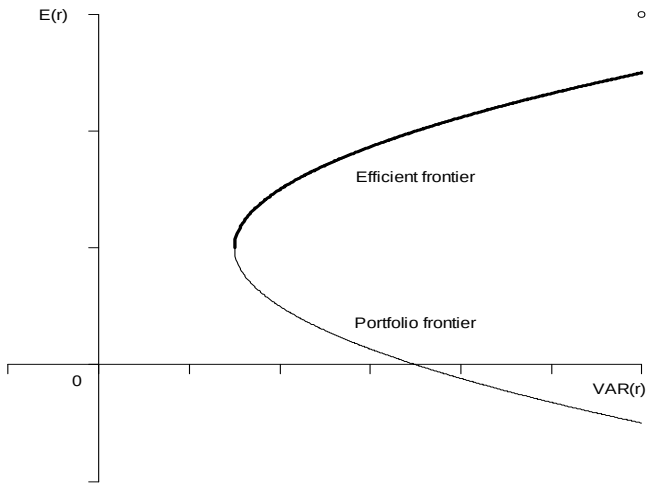
The solution to the minimisation problem summarised in relationships (1), (2) and (3) above is a set of portfolio weights, w_i^*, $i = 1, 2, \ldots, N$, which are such that a portfolio comprising each of the N risky assets, each weighted by the corresponding weight w_i^*, has minimum variance of returns, for given expected return $E^*(R_p)$.

For each possible value of portfolio expected return $E^*(R_p)$, there is a set of weights which results in a portfolio with minimum variance of returns. The set of these portfolios with minimum variance of return is called the portfolio frontier. If portfolio expected return is plotted against minimum variance of return, the resulting graph is a parabola. When expected return is plotted against minimum standard deviation of portfolio return, the graph of the portfolio frontier is a hyperbola.[86] The graph of the portfolio frontier is illustrated in Figure 6 of Appendix 9 to the Explanatory Statement. Figure 8 of Appendix 9 better illustrates the hyperbola obtained when portfolio expected return is plotted against minimum standard deviation.

A key result of portfolio theory is that, given a "target" expected rate of return $(E^*(R_p)$ in equation (2) above), the investor will choose weights for a portfolio which is on the portfolio frontier (the investor will choose a portfolio with minimum variance of returns). Furthermore, if the investor's utility function is increasing and strictly concave, the investor will choose only weights for a portfolio which is represented by a point on the portfolio frontier above and to the right of point of minimum portfolio variance. That part of the portfolio frontier which is above and to the right of the point of minimum variance is called the efficient frontier. Portfolios corresponding to points on the efficient frontier are called mean-variance efficient portfolios.

The portfolio frontier and the efficient frontier are shown in Figure 8.

Figure 8: portfolio frontier and efficient frontier



[86] The shape of portfolio frontier is explained in Huang and Litzenberger.

The key results from portfolio theory are described in paragraph 9 of Appendix 9 of the Explanatory Statement, and illustrated in the accompanying Figure 6.

The next step in the argument is critical for the subsequent derivation of the Sharpe-Lintner CAPM.

Introduction of a risk free asset

As paragraph 10 of Appendix 2 of the Explanatory Statement notes, the explication of portfolio theory so far has assumed that the investor chooses, at time 0, portfolio weights for each of N risky financial assets which are available at that time. The theory should, however, be extended further to allow for the existence of a risk free asset. Consideration should be given to the implications of the investor being able to invest in the risk free asset at time 0, in addition to being able to invest in the N risky assets on offer at that time.

There is no uncertainty about the return on the risk free asset. It provides the investor with the same return in all of the contingent states between time 0 and time 1. In consequence, the variance of the return on the risk free asset is zero.

We represent the rate of return on the risk free asset by r_f, and the corresponding total return by $R_f\ (= 1 + r_f)$. If an investment is made in the risk free asset at time 0, the investor knows, at that time, that the asset will yield a rate of return r_f one period later at time 1, or a total return of R_f.

Introducing the risk free asset extends the set of options available to the investor at time 0, and changes the investor's portfolio choice in an important way. However, the investor is still concerned to minimise the variance of portfolio returns subject to achieving a given expected return on the portfolio which she uses to transfer wealth to time 1.

Given the form of her utility function, the investor is faced with the problem of choosing a portfolio of financial assets to minimise portfolio return variance subject to achieving a specified expected total rate of return, $E^*(R_p)$, and subject to satisfying the "budget constraint" that the total of the amounts invested in the assets is equal the wealth available for investment. The investor is concerned with choosing the set of portfolio weights $w_i,\ i = 0, 1, 2, \ldots, N$, which minimises

$$\mathrm{var}(R_p) = \sum_{i=0}^{N}\sum_{j=0}^{N} w_i w_j\, \mathrm{cov}(R_i,\ R_j) \qquad (4)$$

subject to

$$w_0 R_f + \sum_{i=1}^{N} w_i E(R_i) = E^*(R_p) \qquad (5)$$

and

$$\sum_{i=0}^{N} w_i = 1 \qquad (6)$$

where w_0 is the weight to be given to the risk free asset in the investor's portfolio.

The set of portfolio weights, w_i^*, $i = 0, 1, \ldots, N$, which are such that a portfolio comprising the risk free asset and each of the N risky assets, each weighted by the corresponding weight w_i^*, has minimum variance of returns, for a given expected return $E^*(R_p)$.

This set of weights is obtained from the first order conditions for the constrained minimisation problem represented by relationships (4), (5) and (6) above. These first order conditions are:

$$-\lambda_1 R_f - \lambda_2 = 0, \qquad i = 0 \qquad (7)$$

$$2\sum_{j=0}^{N} w_j \mathrm{cov}(R_i, R_j) - \lambda_1 E(R_i) - \lambda_2 = 0, \qquad i = 1, 2, \ldots, N \qquad (8)$$

where λ_1 and λ_2 are multipliers.[87]

Let w_i^e, $i = 1, \ldots, N$, be the weights for a portfolio comprising only the N risky financial assets, and which is known to be mean-variance efficient (that is, the portfolio corresponds to a point on the efficient frontier of Figure 8 above). If one of the risky assets available to investors (call it asset e) is a mutual fund that holds this mean-variance efficient portfolio, then the portfolio with weights $w_e = 1$ and $w_i = 0$ for all $i = 1, \ldots, N$ except $i = e$, must satisfy the first order conditions (7) and (8) above. Equation (7) requires

$$-\lambda_1 R_f - \lambda_2 = 0, \qquad (9)$$

and, for any risky asset i, equation (8) requires:

$$2\mathrm{cov}(R_i, R_e) - \lambda_1 E(R_i) - \lambda_2 = 0 \qquad (10)$$

Solving (9) and (10) for the multipliers λ_1 and λ_2, and substituting the results back into equation (10) yields:

$$E(R_i) = R_f + \frac{\mathrm{cov}(R_i, R_e)}{\mathrm{var}(R_e)}[E(R_e) - R_f] \qquad (11)$$

Equation (11) characterises the rate of return which an individual investor might expect to earn at time 1 from an investment, at time 0, in a portfolio of assets formed from a risk free asset and N risky assets which are available at that time.

87 Since the objective function (4) is convex and the constraints (5) and (6) are linear, the second order conditions for a minimum are satisfied. Note also that $\sigma_{0j} = 0$; the covariance of the risk free rate of return with the rate of return on each of the N risky assets is zero.

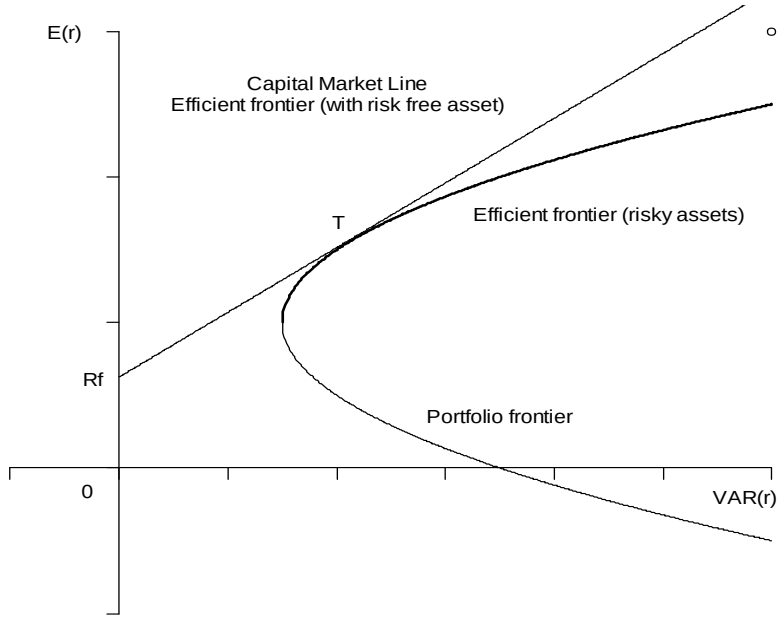
From portfolio theory to the Sharpe-Lintner CAPM

If all investors have the same expectations about the rates of return on risky assets, equation (11) characterises the rate of return which investors, in aggregate, expect to earn at time 1 from an investment, at time 0, in a portfolio of assets formed from the risk free asset and the N risky assets which are available at that time.

In Figure 4 above, we showed the efficient frontier for an investor forming a portfolio from N risky financial assets in accordance with the precepts of portfolio theory. When risk free asset is available to the investor, the efficient frontier is as shown in Figure 9 below (which is similar to Figure 7 of Appendix 9 to the Explanatory Statement).

When a risk free asset with return R_f is available to an investor making a portfolio decision at time 0, the efficient frontier is the straight line through RfT shown in Figure 9. The line through RfT is tangential, at point T, to the efficient frontier for risky assets. This line through RfT is often called the Capital Market Line (Appendix 9 of the Explanatory Statement uses the term "Capital Allocation Line" for a similar line).

Figure 9: Efficient frontier with risk free asset (Capital Market Line)



The expected return and variance of returns of any portfolio represented by a point along the Capital Market Line can be obtained as the expected return and the variance of returns on a portfolio which is a convex combination of two basic portfolios. Those two basic portfolios are the portfolio comprising only the risk free asset, and the portfolio corresponding to the point T. For any constant factor of proportionality α:

$$E(R_i) = \alpha R_f + (1 - \alpha)E(R_T),$$

and

$$\mathrm{var}(R_i) = (1-\alpha)^2 \mathrm{var}(R_T).$$

Setting $\alpha = 1$ provides the investor with a portfolio comprising only the risk free asset: its total return is R_f, and the variance of returns is zero consistent with there being no uncertainty about the return on the risk free asset. Setting $\alpha = 0$ provides the investor with a portfolio comprising only the portfolio corresponding to the point of tangency T: its total return is $E(R_T)$, with variance of returns $\mathrm{var}(R_T)$. Setting $\alpha = 0.5$ provides the investor with an expected return of $0.5 \times [R_f + E(R_T)]$ and variance of returns $0.25 \times \mathrm{var}(R_T)$.

If, in Figure 9, expected return/variance of return combinations to the right of T are desired (consistent with the investor's preferences summarised by her utility function V), and the investor can borrow at the risk free rate R_f, then those expected return, variance of return combinations can be achieved by borrowing and investing the proceeds in the portfolio corresponding to the point of tangency T. If expected return/variance of return combinations to the left of T are desired (consistent with the investor's preferences), and the investor can lend at the risk free rate R_f, then those expected return variance of return combinations can be achieved by lending and investing the proceeds in the portfolio corresponding to the point of tangency T.

We now turn from the individual investor to all investors in the market for financial assets. Let W_k be the amount of wealth individual k invests in the portfolio of risky financial assets (the portfolio corresponding to the point of tangency T in Figure 9), and let X_{ik} be the number of units ("shares") of risky asset i held by that individual. Since all investors hold the same portfolio of risky assets (the portfolio corresponding to point of tangency T),

$$w_i^T = \frac{p_i X_{ik}}{W_k}, \qquad k = 1, 2, \ldots, K$$

where w_i^T is the fraction of wealth invested in asset i in the portfolio corresponding to point of tangency T, p_i is the market price of asset i, and K is the number of investors in the market for financial assets.

Summing over all K investors:

$$w_i^T = \frac{p_i \sum_{k=1}^{K} X_{ik}}{\sum_{k=1}^{K} W_k} \qquad (12)$$

The numerator in (12) is the total market value of asset i, and the denominator is the total value of all risky assets. w_i^T is, then, the fraction of wealth invested in risky assets which is invested in asset i.

The portfolio corresponding to point of tangency T has weights w_i^T, for risky assets $i = 1, \ldots, N$, which are the ratios of the total market values of each of the assets to the total value of all risky assets. The portfolio corresponding to point of tangency T is, therefore, called the market portfolio. Consistent with this terminology, the expected

return on the market portfolio is denoted $E(R_M)$ (instead of $E(R_T)$), and the variance of return on the market portfolio is denoted $var(R_M)$ (instead of $var(R_T)$).

Now, the market portfolio is a mean-variance efficient portfolio which will be observable if aggregate holdings of risky financial assets can be observed. It can replace the undefined mean-variance efficient portfolio e in equation (11) above, so that the return on risky asset i is:

$$E(R_i) = R_f + \frac{cov(R_i, R_M)}{var(R_M)}[E(R_M) - R_f] \qquad (13)$$

$cov(R_i, R_M)$ is the covariance of the return on risky financial asset i with the return on the market portfolio, and the ratio $cov(R_i, R_M)/var\,(R_M)$ is called the beta of asset i (β_i). Equation (13) can written:

$$E(R_i) = R_f + \beta_i[E(R_M) - R_f] \qquad (14a)$$

or, equivalently, as

$$E(r_i) = r_f + \beta_i[E(r_M) - r_f] \qquad (14b)$$

This is the Sharpe-Lintner CAPM.

The Sharpe-Lintner CAPM is a simple linear relationship between the expected rates of return on risky assets and the relative riskiness of those assets, where the measure of that relative riskiness is β.

We showed, in Figure 9 above, the Capital Market Line, which is the frontier of mean-variance efficient portfolios in circumstances where a risk free asset is available to investors. In these circumstances, the return on any mean-variance efficient portfolio p is:

$$E(r_p) = r_f + \frac{E(r_M) - r_f}{var(r_M)} var(r_p) \qquad (15)$$

Now, the slope of the Capital Market Line is $[E(r_M) - r_f]/var(r_M)$: an investor considering a mean-variance efficient portfolio with marginally higher risk would expect an increase in expected return of $[E(r_M) - r_f]/var(r_M)$ per unit of additional risk (as measured by the variance of portfolio returns $var(r_p)$). $[E(r_M) - r_f]/var(r_M)$ is sometimes called the market price of risk.

For a portfolio not on the efficient frontier, which may comprise a single asset, the increase in expected return per unit of additional risk is given by the Sharpe-Lintner CAPM. It is:

$$[E(r_M) - r_f] \times \beta_i = \frac{E(r_M) - r_f}{var(r_M)} cov(r_i, r_M) = \frac{E(r_M) - r_f}{var(r_M)} \times \rho_{iM}\sigma_i\sigma_M \qquad (16)$$

where σ_i and σ_M are, respectively, the standard deviation of returns on asset i and the standard deviation of returns on the market portfolio. Comparing (16) with the market price of risk for a mean-variance efficient portfolio (equation (15)), we can see that the market provides compensation for only a portion of the total risk of an inefficient portfolio (or asset): the portion of risk that is priced is $\rho_{iM}\sigma_i\sigma_M$, which is less than $var(r_i)$ because $-1 \leq \rho_{iM} \leq 1$ and, for given expected return, the variance of return on the (mean-variance efficient) market portfolio is less than the variance of return on portfolio (or asset) i.

From (16), the portion of risk that is priced is $\beta_i var(r_M)$. Since every investor can be considered as holding a portfolio comprising the risk free asset and the market portfolio, the relevant risk for investors is the risk of the market portfolio as measured by the variance of returns on that portfolio $(var(r_M))$. β_i is, then, the contribution of asset i to the total risk of the market portfolio.

Systematic and idiosyncratic risk

The rate of return, r_i, on any risky financial asset i can be decomposed into a part that is correlated with the return on the market portfolio, and a part that is uncorrelated with that return:

$$r_i = \alpha_i + \beta_i r_M + \varepsilon_i$$

where:

(a) $\alpha_i + \beta_i r_M$ is the part of the return that is correlated with the return on the market portfolio; and

(b) ε_i is the part of the return that is uncorrelated with the return on the market portfolio.

The variance of returns on asset i is, then:

$$var(r_i) = \beta_i^2 var(r_M) + var(\varepsilon_i) \qquad (17)$$

$var(r_i)$ is the total risk associated with an investment in financial asset i. It comprises:

(a) $\beta_i^2 var(r_M)$, which is that part of the risk of asset i attributable to the risk of the market portfolio; and

(b) $var(\varepsilon_i)$, which is that part of the risk of asset i attributable to factors other than the return on the market portfolio.

$\beta_i^2 var(r_M)$ is often called the systematic risk, and $var(\varepsilon_i)$ is called the non-systematic risk, or idiosyncratic risk, of risky financial asset i. Using this terminology, the total risk associated with a risky financial asset is the sum of systematic risk and idiosyncratic risk.

The Sharpe-Lintner CAPM can be written:

$$E(r_p) = r_f + \left(\frac{\beta_i^2 var(r_M)}{\beta_i}\right)\left(\frac{E(r_M) - r_f}{var(r_M)}\right) \qquad (18)$$

As noted above, $[E(r_M) - r_f]/var(r_M)$ is the market price of risk. Equation 18 indicates that only the systematic risk of financial asset i is priced: the market equilibrium rate of return on the asset only compensates an investor for bearing systematic risk. Paragraph 26 of Appendix 9 of the Explanatory Statement reaches a similar conclusion from a slightly different perspective.

Systematic risk has an important role to play in the application of the Rate of Return Guidelines. Rule 87(3) requires a benchmark efficient entity which has a similar degree of risk as the service provider in respect of the provision of reference services. The risk to which rule 87(3) refers is, the Explanatory Statement advises, systematic risk (paragraph 203).

A7.2 Absence of arbitrage asset pricing

W_0 is the remainder of an investor's wealth at time 0, after her decision to consume at that time. The investor proposes to transfer this wealth to time 1 to finance consumption at that time by investing in a portfolio, which may comprise a risky financial asset on offer at time 0 and a risk free asset which is available at that time.

The known price of the risky asset at time 0 is p_0. At time 1, the risky asset has price p_1, which may be higher than p_0, in which case it is denoted p^U, U indicating "Up". The price at time 1 may also be lower than p_0, in which case it is denoted p^D, D indicating "Down". The probability of price p^U at time 1 is π; the probability of the lower price p^D at that time is $1 - \pi$. That is, the price of the risky asset is assumed to follow a binomial model.

The one period rate of return on the risk free asset is r_f.

We assume:

$$p^D < (1 + r_f)p^0 < p^U$$

This condition must be satisfied if there is to be no opportunity for arbitrage.[88]

The investor has to decide on how many units of the risky asset ("shares") she will purchase to maximise her expected utility at time 1. If she purchases n shares, with the balance of her wealth being invested in the risk free asset, her wealth at time 1 will be:

$$W_1 = np_1 + (W_0 - np_0)(1 + r_f).$$

If the investor has a utility function $U(W)$ defined over wealth (and not over portfolio returns and return variances as was the case in subsection A7.1 above), her expected utility at time 1 is:

[88] See Steven E. Shreve (2004), *Stochastic Calculus for Finance 1: The Binomial Asset Pricing Model*, pages 2-3.

$$E[U(W_1)] = \pi U(W^U) + (1 - \pi)U(W^D),$$

where W^U is her wealth if the price of the risky asset at time 1 is p^U, and W^D is her wealth at that time if the price of the risky asset is p^D.

The first order condition for expected utility maximisation is:

$$\pi U'(W^U)[p^U - p_0(1 + r_f)] + (1 - \pi)U'(W^D)[p^D - p_0(1 + r_f)] = 0,$$

or

$$E[U'(W_1^*).(p_1 - p_0(1 + r_f)] = 0$$

where W_1^* is the optimal value of wealth at time 1.

The price of the risky asset at time 0 is, then:

$$p_0 = E\left[\frac{U'(W_1^*)}{E[U'(W_1^*)](1 + r_f)} . p^1\right]$$

That is, the price of the risky asset at time 0 is the expected discounted value of its price at time 1, where

$$\frac{U'(W_1^*)}{E[U'(W_1^*)](1 + r_f)}$$

is the stochastic discount factor.

The random variable $z_1 = U'(W_1^*)/E[U'(W_1^*)]$ can take two possible values: z^U, with probability π; and z^D, with probability $1 - \pi$. Define

$\pi^{RN} = \pi z^U$, and $1 - \pi^{RN} = (1 - \pi)z^D$.

The values of z_1 are such that π^{RN} and $1 - \pi^{RN}$ are probabilities, so that the price of the risky asset at time 0 can be written simply as:

$$p_0 = E^{RN}\left[\frac{1}{(1 + r_f)} . p^1\right]$$

where E^{RN} is the expectation under the risk neutral probabilities π^{RN} and $1 - \pi^{RN}$.

That is, the price of the risky asset at time 0 is simply the expected discounted value of its price at time 1, where the future price is discounted at the risk free rate and the expectation is calculated using the probabilities π^{RN} and $1 - \pi^{RN}$. π^{RN} and $1 - \pi^{RN}$ are referred to as risk neutral probabilities. The uncertain payoffs p^U and p^D, weighted by the corresponding risk neutral probabilities, are called the risk neutral or certainty equivalent payoffs.

The current price of a risky financial asset is, then, the discounted value of its risk neutral payoffs, where the appropriate discount rate is the risk free rate of return.

8 Estimation of the cost of corporate income tax

8.1 Rules governing estimation of the cost of corporate income tax

For the purpose of total revenue determination, a service provider's cost of corporate income tax in each year of an access arrangement period is to be estimated using the formula set out in rule 87A. The formula is:

$$\mathrm{ETC}_t = \mathrm{ETI}_t \times r_t \times (1 - \gamma),$$

where

(a) ETC_t is the estimate of the cost of tax in regulatory year t;

(b) ETI_t is an estimate of taxable income for regulatory year t;

(c) r_t is the expected statutory income tax rate; and

(d) γ (gamma) is an estimate of the value to be attributed to imputation credits.

Rule 87A explains that ETI_t is to be an estimate of the taxable income of a benchmark efficient entity which operates the business of the service provider to provide reference services. It is not an estimate of the taxable income of the service provider.

8.2 Estimate of the cost of tax

GGT has estimated the cost of tax, ETC_t, in each regulatory year t, by multiplying an estimate of annual taxable income, ETI_t, by the expected statutory income tax rate, r_t.

Annual taxable income has been estimated as total revenue in each regulatory year less expenses allowed for income tax purposes. These expenses are:

(a) the cost of debt financing – the return on debt from the total revenue calculation;

(b) operating expenses – the forecasts of operating expenditure from the total revenue calculation; and

(c) tax depreciation – depreciation on the historical cost of the assets comprising the GGP which may be depreciated for tax purposes (the tax asset base), calculated using the straight line method with the asset lives determined for taxation purposes by the Australian Taxation Office.

Where appropriate, the annual taxable income has been reduced by any losses which can be brought forward for taxation purposes. To calculate the cost of tax, the current statutory corporate tax rate, 30%, has been applied to the annual estimates of taxable income net of any loss which has been brought forward.

The cost of tax has been estimated from taxable income estimated, in turn, as the difference between:

(a) the total revenue, which would be the revenue earned by a benchmark efficient service provider which uses the Covered Pipeline to provide reference services; and

(b) expenses allowed for income tax purposes which are:

(i) in the case of the cost of debt financing and operating expenses, the costs used to determine the total revenue of the benchmark efficient service provider; and

(ii) in the case of tax depreciation, calculated by applying the rules for depreciation established by the Australian Taxation Office to a tax asset base determined using the capital expenditures of the benchmark efficient service provider.

The taxable income from which GGT has estimated cost of tax is the taxable income of a benchmark efficient entity which operates the Covered Pipeline to provide reference services.

8.3 Value attributed to imputation credits

Under Australian taxation law, company profits are taxed, and dividends paid from the after-tax profits are also taxable as income accruing to Australian resident tax payers. So that a given income stream from company profits is not taxed twice, the law provides for imputation or franking credits to be distributed to equity investors when dividends are paid, providing those investors with a potential offset against their personal tax liabilities.

Rule 87A requires that the estimated cost of corporate income tax be reduced by an amount which represents the value of those imputation or franking credits. The estimation methods, financial models, market data and other evidence which are to be taken into account in estimating the value of imputation credits are to be set out in the rate of return guidelines to be made and published in accordance with rule 87(13) (rule 87(14).

The Rate of Return Guidelines advise:

(a) the value to be attributed to $1 of imputation credits, the parameter gamma (γ), is to be estimated as the product of two components, the payout ratio (F), and the market value per dollar of distributed credits (θ):

$$\gamma = F \times \theta$$

(paragraph 153);

(b) current empirical evidence indicates an estimate of 70% for the payout ratio (paragraph 155); an estimate of 70% is also consistent with the estimate accepted by the Australian Competition Tribunal in its decision in *Application by*

Energex Limited (Distribution Ratio (Gamma)) (No 5) [2011] ACompT 9 (12 May 2011) (paragraph 154);

(c) three methods are available for estimating θ, (i) estimation using tax statistics, (ii) dividend drop-off studies, and (iii) a simultaneous price method (paragraph 156);

(d) tax statistics can provide only an upper bound for the value of θ, and relevant data may not be available for application of the simultaneous price method (paragraph 156);

(e) a number of estimation issues may affect the precision of estimates obtained by applying the dividend drop-off method, but that method provides estimates of market value and is most appropriate for estimating θ (paragraph 157);

(f) finance consultants SFG Consulting used a dividend drop-off study to estimate the value for θ accepted by the Australian Competition Tribunal in *Energex Limited*; that value, 0.35, was the upper limit of a range 0 to 0.35, which SFG has replicated using more recent data (paragraph 157, Table 1);

(g) the ERA's dividend drop-off study provides an estimate of the value for θ in the range 0.35 to 0.55 (paragraph 157, Table 1); and

(h) the permissible range of theta is 0.35 to 0.55; this range implies – given a payout ratio of 0.70 – a range for gamma of 0.25 to 0.39.

8.4 Estimation of the payout ratio

Paragraph 928 of the Explanatory Statement advises that:

(a) existing evidence supports the use of a range for the payout ratio of 0.70 to 1.00;

(b) the lower bound of 0.70 is supported by the empirical evidence of Hathaway and Officer;

(c) the upper bound of 1.00 is based on the assumption that all profits are distributed by firms in the year they are created; and

(d) in the absence of any new evidence or analysis, the ERA has no basis to depart from the finding of the Australian Competition Tribunal and considers that an appropriate estimate of the payout ratio is 0.70.

GGT is of the view that:

(a) the finding of the Tribunal that the evidence supports an estimate of the payout ratio of 0.70 is important to confirmation that an estimate of 0.70 is currently appropriate when applying rule 87A; and

(b) the Tribunal decision was made prior to the November 2012 amendments to the NGR which introduced rule 87A, and the question of whether or not there is a basis for departing from the finding of the Tribunal is not the criterion which should now be applied in determining an estimate of the payout ratio.

Nevertheless, the evidence adduced by the ERA and reported in the Explanatory Statement supports an estimate of 0.70.

GGT has, through its relationship with APA Group, obtained, and is able to make use of, a report by financial consultants SFG Consulting, *An appropriate regulatory estimate of gamma*, which was prepared in March 2014 (SFG Report). The SFG Report, which is attached as Appendix 1 to the Supporting Information, confirms that a payout ratio estimate of 0.70 is currently appropriate when applying rule 87A.

8.5 Estimation of θ

The estimation of θ has been debated at some length. Multiple methods of estimation are available, but dividend drop-off studies have the important advantage that they can provide direct estimates of the observed market value of a franking credit (Explanatory Statement, paragraph 959).

The Explanatory Statement notes that a number of estimation issues may affect the precision of estimates obtained by applying dividend drop-off methods (paragraph 959). These arise from heteroskedasticity, multicollinearity and the presence of outliers in the dividend data (Explanatory Statement, Appendix 28). In its work to estimate θ, the ERA has sought to mitigate the effects of these three estimation issues by using regression methods which are robust in the presence of deviations from the assumptions of the standard linear regression model (Explanatory Statement, paragraph 952).

The most relevant dividend drop-off studies currently available are the study by SFG Consulting which provided the estimate θ accepted by the Australian Competition Tribunal in *Energex Limited*, and the study by Vo, Gellard and Mero.[89] These studies indicate that an acceptable range for θ is 0.35 to 0.55 (Explanatory Statement, paragraph 959).

The acceptable range for θ in the Rate of Return Guideline (and the Explanatory Statement) appears to be from the results obtained across four variants of a basic dividend drop-off model the parameters of which were estimated by Vo, Gellard and Mero using (robust) MM and Least Absolute Deviation regression methods.

A further issue, noted in the Explanatory Statement, arises from the way in which the "drop-off" in dividend is measured. Paragraph 955 explains that, in some dividend

[89] SFG Consulting, *Dividend drop-off estimate of theta, Final Report, Re: Application by Energex Limited (No 2) [2010] ACompT 7*, 21 March 2011.

Duc Vo, Beauden Gellard, Stefan Mero (2013), "Estimating the Market Value of Franking Credits: Empirical Evidence from Australia", paper presented at 42nd Australian Conference of Economists, available at http://www.murdoch.edu.au/School-of-Management-and-Governance/Australian-Conference-of-Economists/.

drop-off studies, the ex-dividend share prices have been adjusted to account for the variation in those prices which can be attributed to the variation in market returns. In particular, this adjustment – the "market return correction" – was made to the data used in the study by SFG Consulting which provided the estimate of θ accepted by the Australian Competition Tribunal in *Energex Limited* (Explanatory Statement, paragraph 956). SFG Consulting reported, and the Competition Tribunal accepted, a range for θ of 0 to 0.35.

The use of the market return correction appears to be the principal reason for the difference between the range for θ obtained by SFG Consulting, and the range reported by Vo, Gellard and Mero. In its 2011 report provided to the Tribunal, SFG Consulting advised that the range for θ was 0 to 0.35, and that the estimate of θ from its Model Specification 4 was 0.35. Vo, Gellard and Mero report a range for θ of 0.29 to 0.44 (with the market return correction made to the data), and an estimate of θ from Model Specification 4 of 0.33. The range for θ reported by Vo, Gellard and Mero is from four model specifications using two robust estimation methods (MM and Least Absolute Deviation).[90] The average of the range is 0.34. When Vo, Gellard and Mero apply the market return correction to their data, their estimate for θ is very similar to that which was obtained by SFG Consulting.

Should the market return correction be made?

Paragraph 956 of the Explanatory Statement contends that applying the market return correction in the estimation of θ is incorrect for the following reasons:

(a) the market fluctuations which mask investors' true valuations of franking credits are random, and are therefore already accounted for by the error terms of the regression models; and

(b) the value for θ is not a value which requires the assumption that aggregate market movements are known in advance by investors.

The Explanatory Statement argues that the market fluctuations which mask investors' true valuations of franking credits are random, and are therefore already accounted for by the error terms of the regression models. This seems to be a claim made in respect of the model represented by equation 9 in Vo, Gellard and Mero:

$$P_{c,i} - P_{x.i} = \delta D_i + \theta FC_i + \varepsilon_i,$$

where:

(a) P_{ci} is the cum dividend price of the shares of company i;

(b) P_{xi} is the ex dividend price of the shares of company i;

(c) δ is the market value of cash dividends as a proportion of their face value;

(d) D_i is the dividend paid by company i;

[90] The four model specifications are set out in Table 44 of the Explanatory Statement.

(e) θ is the market value per dollar of distributed franking credits;

(f) FC_i is the value of the franking credit associated with the dividend of company i; and

(g) ε_i is an error term

Equation 9 is similar to equation 1 in SFG Consulting's 2011 dividend drop-off study. Both equations purportedly fully explain the difference between the cum dividend and the ex dividend share prices in terms of the dividend and the franking credit.

The change in the price of the shares of company i over the ex dividend day is, however, not attributable solely to the dividend paid by company i and to the associated franking credit. It is also attributable to the daily expected return on the shares in company i. Even if no dividend were paid, the share price would change over the day by the daily expected return, which is determined by market-wide factors. This change in the share price which can be attributed to the daily expected return is not a purely random factor to be accounted for by the error term of a regression model. It can, and should, be removed from the observed ex dividend share price to allow more precise measurement of the value of the dividend and of the franking credit.

SFG Consulting removed the effect of the daily expected return in its 2011 dividend drop-off study. The market return correction was also made in the earlier dividend drop-off study of the value of imputation credits reported by Beggs and Skeels.[91]

If $P_{i,x}^o$ is the observed ex dividend share price, the corrected price to be used in estimating θ, $P_{i,x}$, is:

$$P_{i,x} = \frac{P_{i,x}^o}{1 + E(r_i)}$$

where $E(r_i)$ is the expected return on the shares of company i over the ex dividend day .

$E(r_i)$ can be estimated for each company i, in a sample of companies which have paid dividends, using the Sharpe-Lintner CAPM, or it can be estimated for each company by estimating the market model

$$R_i = \alpha_i + \beta_i R_M + \varepsilon_i.$$

Beggs and Skeels, and later SFG Consulting, approximated the expected daily return on each company in the sample of companies which paid dividends by assuming:

(a) expected rates of return are explained by the Sharpe-Lintner CAPM;

[91] David J Beggs and Christopher L Skeels (2006), "Market Arbitrage of Cash Dividends and Franking Credits", Economic Record, 82(258), pages 239-252.

(b) the equity betas for each of the companies in the sample was approximately equal to 1.0, the equity beta of the market portfolio; and

(c) the return on the market portfolio over the ex dividend day can be measured as the return on the portfolio from which the All Ordinaries Index was calculated.

Their ex dividend share prices corrected for the expected daily return were, then:

$$P_{i,x} = \frac{P_{i,x}^{o}}{1 + r_M}$$

where r_M is the rate of return on the All Ordinaries Index over the ex dividend day.

Vo, Gellard and Mero are of the view that the assumption that the Sharpe-Lintner CAPM fully explains expected returns, and the assumption that the equity betas are approximately equal to 1.0, are extremely strong assumptions. However, they provide no reasons for why this might be the case, and for why their preferred approach of not making a market return correction is superior when, in fact, it is theoretically and empirically unsound. By removing that component of the change in the share price over the ex dividend day which can be attributed to the variation in the market, the variance of the ex dividend, cum dividend price difference is reduced, leading to greater precision in the estimates of the value of the dividend and the value of the franking credit.

The SFG Report (provided as Appendix 1 to the Supporting Information) advises:

(a) the standard approach in dividend drop-off studies is to assume that, but for the dividend, the share price would have followed the movement in the broad market over the ex dividend day; and

(b) recent papers in peer reviewed journals make such an adjustment, as indicated by Vo, Gellard and Mero presenting results obtained by applying the market return correction for comparison with the results of other studies.[92]

Neither of the objections to the market return correction raised in the Explanatory Statement can, in these circumstances, be sustained. The market return correction removes a non-random effect, an effect which cannot be properly accounted for by the error terms of a regression model, from the data, and thereby leads to a better defined (lower variance) estimate of θ. There is no assumption that aggregate market movements are known in advance by investors, although investors are assumed to form expectations about the rates of return in the way assumed in the derivation of the Sharpe-Lintner CAPM.

McKenzie and Partington may have argued, as paragraph 955 of the Explanatory Statement notes, that the market return correction will have no impact on the final value of θ. However, the results reported by Vo, Gellard and Mero indicate that this might not be the case.

[92] SFG Report, page 51.

Furthermore, Beggs and Skeels may have noted that the correction is imperfect.[93] It is. The market return correction applies the Sharpe-Lintner CAPM using the assumption that, for each of the companies from which data has been sourced for θ estimation, $\beta = 1$. Clearly, this is an approximation. Nevertheless, if the Sharpe-Lintner CAPM is accepted as a valid model for estimation of equity returns (indeed, paragraph 113 of the Rate of Return Guidelines advises that it is the only model to be used for estimation of equity returns), then the approximation which is made can be expected to yield a more accurate estimate than would have been the case if the market return correction had not been made.

The All Ordinaries Index is used, in the market return correction, to provide a measure of the expected rate of return on the market portfolio. The fact that the shares of companies included in the sample for estimation have a market capitalisation greater than 0.03% of the All Ordinaries Index, as noted in paragraph 955 of the Explanatory Statement notes, is largely irrelevant.

Concluding that the market return correction should not be made leads to error. It leads to an estimate of the value of imputation credits to investors in a regulated business which is higher than it should be. In consequence, the estimate of the cost of tax determined using the formula of rule 87A is too low, and the service provider is not provided with a reasonable opportunity to recover at least the efficient costs incurred in providing reference services.

An estimate of θ made by applying the market return correction to the ex dividend share prices better meets the requirements of the NGL and the NGR that an estimate made using those share prices without the correction.

8.6 GGT's estimate of the value to be attributed to imputation credits

GGT has estimated the value to be attributed to $1 of imputation credits, the parameter gamma (γ), as the product of the payout ratio, and the market value per dollar of distributed credits (θ).

In estimating gamma, GGT has used the estimate of 70% for the payout ratio which is indicated in the Rate of Return Guidelines.

In its report for APA Group, SFG has confirmed that this estimate is consistent with current empirical evidence.

GGT has used an estimate of 0.35 for θ for the purpose of estimating gamma. This is the estimate made by SFG Consulting in 2011 and accepted by the Australian Competition Tribunal in *Energex Limited*. The SFG Consulting study used the dividend drop-off method, and is one of two current studies which, the Explanatory Statement advises, is relevant to the estimation of θ. SFG has replicated the results of that study using more recent data, and its results are confirmed by work of Vo, Gellard and Mero when they – correctly – apply the market return correction.

[93] Explanatory Statement, paragraph 955.

The estimate of gamma which GGT has used when estimating the cost of corporate income tax for the GGP in accordance with the requirements of rule 87A is, therefore, 0.25 (= 0.70 x 0.35). This is the lower limit of the indicated range for gamma in paragraph 158 of the Rate of Return Guidelines.

9 Operation of an incentive mechanism

The GGP Access Arrangement imposes a cap on the price (reference tariff) at which GGT can provide the reference service using the Covered Pipeline. This price cap provides an incentive for GGT to pursue efficiency gains during an access arrangement period.

The GGP Access Arrangement does not include a more specific incentive mechanism and, in consequence, there are no increments for efficiency gains from the operation of such a mechanism in the previous access arrangement period, and no decrements for efficiency losses, which are to be carried over into the total revenue for the period 1 January 2015 to 31 December 2019.

10 Forecast operating expenditure

GGT's forecast of expenditure expected to be incurred in operating the Covered Pipeline during the period 2015 to 2019 is set out and explained in this section of the Supporting Information.

10.1 Rules governing operating expenditure

The forecast of operating expenditure used in establishing the total revenue for an access arrangement period should be an estimate of the expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services (rule 91(1)).

Rule 69 the defines operating expenditure for the purpose of price and revenue regulation as "operating, maintenance and other costs and expenditure of a non-capital nature incurred in providing pipeline services and includes expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services".

10.2 Operating expenditure over the earlier access arrangement period

Table 23 shows operating expenditures for the Covered Pipeline, for the period 1 January 2010 to 31 December 2014. The expenditures shown in the table for the period 2010 to 2013 are actual expenditures. The expenditure for 2014 is a forecast comprising actual expenditure for the period 1 January 2014 to 31 March 2014, and an estimate for the remainder of the year.

The operating expenditures in Table 23 (and in subsequent tables) are divided into four major categories. These are:

(a) APA operations: expenditures in this category are expenditures incurred by APT Pipelines (WA) Pty Ltd in providing engineering and field technical services for the operation of the Covered Pipeline;

(b) GGT operations: expenditures in this category are expenditures incurred directly by the manager, Goldfields Gas Transmission Pty Ltd, in managing the operation of the Covered Pipeline;

(c) APA commercial operations: expenditures in this category are expenditures incurred by APT Goldfields Pty Ltd in providing the services required for commercial operation of the Covered Pipeline; and

(a) Corporate costs: the costs of APA Group corporate functions which provide services to Covered Pipeline.

The operating expenditures for the Covered Pipeline in 2010, 2011 and 2013 have been reviewed by GGT's external auditor. The auditor's review reports are provided in Attachment 9 to the Supporting Information.

Table 23: Operating expenditure: 2010-2014

	2010 Actual $ million	**2011** Actual $ million	**2012** Actual $ million	**2013** Actual $ million	**2014** Forecast $ million
Pipeline operations	13.444	13.595	13.660	12.487	13.711
Commercial operations	1.046	1.032	1.845	2.470	2.069
Regulatory costs	2.117	1.362	0.421	0.775	2.284
Insurance	0.827	0.755	0.695	0.769	0.707
Corporate costs	7.080	8.712	7.990	6.359	6.205
[redacted]					
	24.515	**25.455**	**24.611**	**22.860**	**24.977**

The expenditures shown in Table 23 are nominal expenditures; they include the effects of changes in the level of prices (inflation). To facilitate comparison between the expenditures of Table 23 and the forecast operating expenditures shown in Table 25, the expenditures in Table 23 have been converted to real expenditures at the prices prevailing in the December quarter 2013. These real (December 2013) expenditures are shown in Table 24.

Table 24: Operating expenditure: 2010-2014: $ December 2013

	2010 Actual $ million	**2011** Actual $ million	**2012** Actual $ million	**2013** Actual $ million	**2014** Forecast $ million
Pipeline operations	12.961	12.473	12.913	11.952	12.676
Commercial operations	2.711	2.886	3.017	3.004	2.645
Regulatory costs	2.289	1.430	0.432	0.775	2.218
Insurance	0.894	0.793	0.715	0.769	0.686
Corporate costs	7.658	9.149	8.209	6.359	6.025
[redacted]					
	26.513	**26.731**	**25.287**	**22.860**	**24.249**

10.3 Forecasting method and key assumptions

GGT has developed its forecast of operating expenditure for the period 1 January 2015 to 31 December 2019 using the method which was used to forecast that expenditure for reference tariff determination for the current access arrangement period. GGT considers that this method remains the most appropriate for forecasting operating expenditure for the forthcoming period because it provides the best forecast or estimate available in the circumstances, as required under rule 74(2).

GGT periodically prepares a detailed operating expenditure budget for five years ahead for the GGP. The current version of the five-year budget was prepared in early in 2014, and has been reviewed and approved by the GGT JV. In circumstances where a detailed and approved budget is available for use in preparing proposed revisions to an access arrangement, GGT considers that that budget is the best available information as to the costs likely to be incurred by the service provider in the forthcoming access arrangement period.

GGT has used the approved five-year operating expenditure budget for the GGP as the basis for its forecast of operating expenditure for the Covered Pipeline for the period 1 January 2015 to 31 December 2019. The budget has been used in the following way:

(a) all forecast expenditures directly attributable to uncovered assets have been removed;

(b) forecasts of expenditure attributable to both the Covered Pipeline and uncovered assets have been allocated to the Covered Pipeline using the ratio of TJ km/d of service provided using the Covered Pipeline to total TJ km/d of service provided using the Covered Pipeline and the uncovered assets (with some 7.6% of total expenditure being allocated in this way);

(c) a “base year” of actual expenditure has been selected and the five-year budget forecasts of have been compared against the base year; and

(d) significant differences have been identified and, where appropriate, adjustments have been made to the budget forecasts.

GGT has chosen 2012 as the base year for assessing the efficiency and prudency of forecast of operating expenditures for the period 2015 to 2019. This year was chosen as the base year for the following reasons:

(a) expenditure during 2012 is representative of expenditures during the period 2010 to 2014;

(b) certain specific factors, which are discussed below, caused expenditures on the Covered Pipeline in 2013 and 2014 to be abnormally low, and therefore not representative of future expenditures;

(c) those specific factors began to have effect during 2012, but the effects on expenditure in that year, although apparent, were not large; and

(d) operating expenditure attributed to the Covered Pipeline in 2012 has been reviewed by GGT's external auditor, and the auditor's review report is provided in Attachment 9 to the Supporting Information.

10.3.1 Factors causing expenditures in 2013 and 2014 to be low

Total operating expenditure for the year 2013 was some $22.9 million ($ December 2013). It was around 90% of expenditure in 2012, and around 90% of the average operating expenditure for the five years 2010 to 2014.

Total operating expenditure for 2013 was abnormally low. Expenditure in 2014 was similarly lower than the average for the period 2010 to 2014, but by around only 6%.

The difference between the total operating expenditures for 2012 and 2013 is a result of:

(a) lower component expenditures in the categories APA operations - Engineering, APA operations - Field services, and GGT operations - administration; and

(b) smaller increases over 2012 in the categories GGT operations – recoverable and APA commercial operations – Carbon liability.

[redacted]

Engineering and technical labour was in short supply in late in 2012 and during the first half of 2013.[94] APA Group engineering and technical staff (in the Engineering and Fields Services groups) were reassigned from work on the Covered Pipeline to support major pipeline expansion in the Pilbara.

This reassignment of engineering and technical staff continued into 2014, but by June 2014 most of the expansion work had been completed and staff involved returned to the tasks of operating and maintaining the Covered Pipeline.

[redacted]

94 Labour market conditions in Western Australia were tight during 2012 and the first half of 2013 with employment reaching a peak in January 2013. Demand from the resources sector was particularly strong. (See Government of Western Australia, *2012-13 Budget, Economic and Fiscal Outlook*, Budget Paper No. 3, page 25; and 2014-15 *Budget, Economic and Fiscal Outlook*, Budget Paper No. 3, page 34.) APA Group competes for engineering and technical staff with companies in the resources sector.

These factors do not reflect a change in underlying "head-count"; they reflect only a change in the allocation of staff between operations and capital projects. The period from 2013 to 2014 showed a marked increase in work on new (and subsequently uncovered) assets, in an environment of a tight labour market where staff diverted to work on capital projects were not able to be replaced. GGT is not forecasting significant work on major GGP capital projects in the period 2015 to 2019, and the labour market has also softened. Staff have returned to previous roles, and the allocation of activity between operations and capital projects is returning to its historic level. The 2012 operating expenditure is, then, expected to be representative of future operating expenditure on the Covered Pipeline.

Corporate costs, and expenditures in the categories GGP operations – Recoverable and Carbon liability in 2013 were all different from the corresponding expenditures in 2012. These differences are considered below (in section 10.5) in the context of comparison of the forecast operating expenditure with expenditure in the base year. They are not factors to be considered in understanding why expenditures in 2013 and 2014 were abnormally low.

Operating expenditure in 2013 and, to a lesser extent, expenditure in 2014 were lower than in 2012 because resources – people – were not available during the tight labour market conditions during 2013. Operating expenditures in those years are not representative of recurrent expenditures incurred in operating and maintaining the Covered Pipeline, and neither 2013 nor 2014 can be taken as the base year for assessing expenditure forecasts for the period 2015 to 2019.[95]

10.3.2 Removal of irrelevant costs from base year expenditure

For the purpose of establishing a benchmark for operating expenditure, GGT has removed expenditure on "Major expenditure jobs" from the 2012 expenditure.

Major expenditure jobs (MEJs) are large scale, non-recurrent maintenance activities. They are not meaningfully compared as between one year and the next, or across access arrangement periods. The expenditure on MEJs must be excluded from the 2012 operating expenditure for the purpose of establishing the benchmark against which the expenditure forecast for 2015 to 2019 is to be compared.

With the exclusion of the expenditure on MEJs, the expenditures for 2012 shown in Table 23 and, in December 2013 dollars, in Table 24, are representative of the operating expenditure for the Covered Pipeline. All other expenditure is relevant to the operation of the Covered Pipeline, and should be included in the base year costs.

10.4 Forecast operating expenditure for the period 1 January 2015 to 31 December 2019

Forecast operating expenditures for the Covered Pipeline, for the period 1 January 2015 to 31 December 2019, are shown in Table 25.

95 Operating expenditure for 2014 has the further issue that it is forecast, and not actual. An audit review of the expenditure will not be conducted until early in 2015, once the "actual" is known.

The expenditures shown in Table 25 are nominal expenditures; they include the effects of changes in the level of prices (inflation). To facilitate comparison with the base year (2012) expenditures, the forecast operating expenditures shown in Table 25 have been converted to real expenditures at the prices prevailing in the December quarter 2013. These real (December 2013) expenditures, together with the corresponding base year expenditures, are shown in

Table 26.

Table 25: Forecast operating expenditure: 2015-2019

	2015 $ million	2016 $ million	2017 $ million	2018 $ million	2019 $ million
Pipeline operations	13.227	14.063	14.927	14.874	14.953
Commercial operations	2.619	2.731	2.816	2.901	2.988
Regulatory costs	2.301	1.275	0.859	1.330	2.297
Insurance	0.739	0.761	0.784	0.808	0.832
Corporate costs	6.391	6.583	6.781	6.984	7.194
[redacted]					
	25.277	**25.413**	**26.168**	**26.897**	**28.263**

Table 26: Base year and forecast operating expenditures: $ December 2013

	2012	2015	2016	2017	2018	2019
	$million	$ million	$ million	$ million	$ million	$ million
Pipeline operations	12.913	12.468	12.870	13.263	12.831	12.523
Commercial operations	3.017	2.468	2.499	2.502	2.502	2.502
Regulatory costs	0.432	2.169	1.167	0.764	1.147	1.924
Insurance	0.715	0.697	0.697	0.697	0.697	0.697
Corporate costs	8.209	6.025	6.025	6.025	6.025	6.025
[redacted]						
	25.287	**23.826**	**23.257**	**23.250**	**23.202**	**23.670**

10.5 Comparison of the forecast with the base year operating expenditure

Forecast expenditures in each of the four main categories identified in section 10.2 are relatively stable across the period 2015 to 2019. However,

Table 26 indicates a number of differences between those expenditures and the corresponding expenditures in the base year

[redacted]

Corporate costs attributable to the Covered Pipeline constitute approximately 26% of total operating expenditure. Forecast expenditures in this category are significantly – 27% in real terms – lower than expenditure in the base year. The reasons for this difference are discussed in section 10.5.4 below.

10.5.1 APA operations expenditure

Three subcategories of expenditure comprise APA operations expenditure. They are:

(a) Administration (business services): expenditure incurred in providing the administrative and office services required to support APA provision of pipeline engineering and field services to the Covered Pipeline;

(b) Engineering: expenditure incurred in providing the specialist engineering support required for pipeline operation and maintenance, and for the execution of the minor projects required to sustain day-to-day operations;

(c) Field services: expenditure incurred in "on site" or "in the field" operation and maintenance of the Covered Pipeline.

Administration (business services)[96]

Administration (business services) expenditure is approximately 1.4% of the total operating expenditure for the Covered Pipeline over the period 2015 to 2019. Forecast expenditure [redacted] is [redacted] some 20%, below the corresponding expenditure for the base year.

This variation, from a relatively small base amount, does not make a material contribution to the difference between the base year operating expenditure and the forecasts for 2015 to 2019.

Engineering

Engineering is the professional engineering support provided to pipeline operation and maintenance, and includes integrity assurance and management; risk assessment and mitigation; the maintenance of mechanical and rotating equipment engineering; the maintenance of electrical equipment, control systems and instrumentation; industrial data communications engineering; cathodic protection; and technical compliance management and reporting.

Engineering expenditure comprises some 6% of forecast operating expenditure for the Covered Pipeline. Annual expenditures over the period 2015 to 2019 are [redacted] lower than the corresponding expenditure for the base year.

This decrease reflects reassignment of personnel from work on facilities comprising the Covered Pipeline to operation and maintenance of the uncovered pipeline and providing support to projects expanding the Uncovered Pipeline and the realisation of efficiency gains.

Field services

Annual field services expenditure is approximately 35% of the forecast operating expenditure for the Covered Pipeline. It is a major component of the total expenditure.

Field services activities include overall monitoring and control of the pipeline, operation and routine maintenance of field plant and equipment, operational and statutory monitoring and inspections, maintenance and patrolling of the pipeline right of way, liaison with the technical staff of users taking delivery of gas, liaison with landowners and related public relations, warehousing and spares inventory management, vehicle fleet management, and record keeping and reporting.

Annual field services expenditures for the period 2015 to 2019 are some [redacted] 1% lower (in real terms) than the corresponding base year expenditure.

This decrease reflects efficiency improvements in a wide range of field services activities.

96 The subcategory "Administration" appears under each of three of the four major categories of operating expenditure. The expenditures are for administration of three different types of activity, accrued out in three different entities and in three different contexts. There use of the three subcategories of administration does not imply any “double counting” of expenditure on administrative functions.

10.5.2 GGT operations expenditure

Subcategories within the major expenditure category GGT operations include:

(a) administration

(b) APA operations recoverable

(c) APA operations management;

(d) APA commercial management;

(e) marketing;

(f) Newman;

(g) projects/operations

(h) public relations; and

(i) technical regulatory.

The forecasts of expenditure on marketing, public relations and technical regulatory activities are small, and consistent with no expenditure in each of those categories in the base year. They are not considered further.

Administration

Administration expenditure is expenditure on the administrative and office services supporting the overall management of the Covered Pipeline. It also includes rents paid for business premises, pipeline licence fees and the safety levy payable to the Department of Mines and Petroleum.

Expenditures in this subcategory constitute around 7% of the operating expenditure for the Covered Pipeline during the period 2015 to 2019.

Forecast annual expenditure on Administration for the years 2015 to 2019 is some 1% [redacted] lower (in real terms) than the corresponding base year expenditure. The difference does not make a material contribution to the difference between the base year operating expenditure and the forecasts of operating expenditure for 2015 to 2019.

APA operations recoverable

The principal providers of services to the Covered Pipeline are APT Pipelines (WA) Pty Ltd (providers of engineering and field services), and APT Goldfields Pty Ltd (providers of commercial operations services). Personnel employed by each of these companies work in business premises rented by GGT, and GGT recovers a portion of the rent its pays from each of the two service providers. This recovery of premises rent is accounted for as a reduction in total cost of operating the Covered Pipeline.

In 2012, GGT moved from office accommodation in Australia Place, in William Street in the Perth CBD, to lower cost accommodation, in Adelaide Terrace, on the outskirts of the CBD.

The reduction in the recoverable amount [redacted] during the period 2015 to 2019, reflects the reduction in rent resulting from the relocation to Eastpoint Plaza in Adelaide Terrace.

APA operations management

GGT, as manager of the Covered Pipeline, has a contract with APT Pipelines (WA) Pty Ltd for the provision of engineering and field services for the operation and maintenance of the Covered Pipeline (forecast expenditures which were discussed above). APT Pipelines (WA) also undertakes the overall management of engineering and field services delivery, and related activities including engineering and field staff recruitment and development, and the maintenance of field plant and equipment.

Forecast expenditure on the management of engineering and field operations over the period 2015 to 2019 is approximately 6% of the total operating expenditure for the Covered Pipeline. The annual forecasts of expenditure are approximately 21% lower (in real terms) than the corresponding expenditure in the base year.

The reduction is consistent with the reductions in forecast engineering and field services expenditures noted above.

APA commercial management

GGT, as manager of the Covered Pipeline, has a contract with APT Goldfields Pty Ltd for the provision of services which support the commercial operation of the Covered Pipeline (forecast expenditures on these services are discussed below). In addition to providing the services themselves (principally marketing the services of the Covered Pipeline, negotiating gas transportation agreements, and the ongoing administration of those agreements), APT Goldfields also undertakes the overall management of commercial operations, and related activities including the identification of new business opportunities; management of relationships with industry associations, with local governments and the Government of Western Australia, and with the agencies of government including the technical and economic regulators; public relations; and commercial staff recruitment and development.

Forecast expenditure on the management of commercial operations over the period 2015 to 2019 is approximately 5% of the total operating expenditure for the Covered Pipeline. The annual forecasts of expenditure are approximately 11% lower (in real terms) than the corresponding expenditure in the base year.

Newman

A number of lateral pipelines extend from the GGP mainline to user facilities (which are often mine sites or electricity generators). These laterals, with one important exception, are not parts of the Covered Pipeline. They are operated under separate

pipeline licences issued in accordance with the licencing provisions of the Petroleum Pipelines Act 1969. The important exception is the Newman Lateral.

The Newman Lateral is some 48 kilometres of 200 millimetre (nominal) diameter pipeline, which provides a connection between the main line and electric power generation facilities located close to the town of Newman.

GGT uses a contractor to provide field services for the operation and maintenance of the Newman Lateral. Forecast expenditure in this subcategory [redacted] is higher (in real terms) than the base year expenditure. [redacted]. The amount paid annually to the contractor depends on the work to be done on the lateral and, overall, the difference is not material either in the context of GGT operations expenditure, or operating expenditure for the Covered Pipeline.

Projects/operations

Expenditure in this subcategory is for operations-related projects, and the forecasts are for the repair of damage to the pipeline easement, and to surface facilities which are part of the Covered Pipeline, as a result of cyclones.

The Bureau of Meteorology advises, on its website, that:

The Pilbara coast experiences more cyclones than any other part of Australia. Since 1910 there have been 48 cyclones that have caused damaging wind gusts in excess of 90 km/h in the Karratha, Dampier and Roebourne region. On average this equates to about one every two years. About half of these cyclones have an impact equivalent to a category one cyclone. Ten of these: 1925, 1939, 1945, 1954, Shirley 1966, Sheila-Sophie 1971, Trixie 1975, Chloe 1984, Orson 1989 and John 1999 have caused very destructive wind gusts in excess of 170 km/h.

. . .

Since the 1960s the development of the mining and offshore oil and gas industries has increased the damage potential of cyclones. Substantial economic losses can be incurred even with the threat of a cyclone impact owing to lost production or disruptions to shipping activities. Fortunately the modern towns of Karratha and Dampier have been built according to cyclone wind ratings and are far less susceptible to damaging winds than those properties in earlier times.[97]

GGT notes that although cyclones are most destructive along the coast, they weaken and bring heavy rains to inland regions. This rainfall can cause significant damage to the easement of the Covered Pipeline even when surface facilities are unaffected.

Although relatively frequent, the timings of cyclones, their intensities and the areas they affect are all, at least to some extent, unpredictable.

GGT did not incur any expenditure for repairs to its facilities and restoration of the Covered Pipeline easement in the base year. [redacted]

[97] http://www.bom.gov.au/cyclone/history/wa/roebourne.shtml, accessed 24 June 2014.

[redacted]

[redacted]

10.5.3 APA commercial operations expenditure

APA commercial operations expenditure comprises expenditures on:

(a) administration;

(b) legal;

(c) marketing;

(d) public relations;

(e) regulatory;

(f) carbon liability;

(g) communications equipment lease and maintenance; and

(h) insurance

Administration

Expenditure on administration provides the administrative and office services directly supporting commercial operations for the Covered Pipeline.

The annual forecasts of expenditure on the administration of commercial operations for the period 2015 to 2019 are, in real terms, about the same as the corresponding expenditure in the base year.

Legal

Legal services are an important input into the commercial operation of the Covered Pipeline. Legal advice is required when new gas transportation agreements are negotiated, when existing agreements are modified or extended, and when contractual matters are in dispute or a user defaults.

A number of existing gas transportation agreements terminate during the period 2015 to 2019, and others effectively become one year contracts with the users having the right to recontract annually in the later years of long term agreements.

Legal services for commercial operations are generally sourced externally, and the base year expenditure is unrepresentative of the current costs of these services. Forecast expenditure for the period 2015 to 2019 is higher [redacted], but not excessively so at around 1% of total operating expenditure.

Marketing

Markets expenditure is expenditure incurred in activities intended to generate new business for the Covered Pipeline, and to secure the retention of existing users.

Expenditure of this type is important in the market served by GGT. Smaller prospective users, and smaller existing users with gas transportation agreements due for renewal, now have as many as three options, in addition to gas delivered by pipeline, for meeting their future energy needs. These options are diesel, liquefied natural gas, and compressed natural gas.

Forecast expenditure on marketing over the period 2015 to 2019 is [redacted] almost identical to the corresponding expenditure in the base year.

Public relations

A small allowance, $0.004 million, has been provided for commercial operations public relations expenditure in each year of the period 2015 to 2014. Expenditure in the base year was $0.017 million. Through this expenditure contributions were made to community development programs in remote areas.

Regulatory

Regulatory expenditure comprises:

(a) expenditure to meet the standing and other charges levied by the ERA on the Covered Pipeline; and

(b) GGT regulatory expenditure: expenditure incurred by GGT in responding to economic, environmental and other (for example, gas quality specification) regulation which impacts on, or which may impact on, the Covered Pipeline.

Regulatory expenditure was relatively low in the base [redacted] However, as noted earlier, 2012 was “mid regulatory cycle” and regulatory expenditures in that year were relatively low.

GGT’s forecasts of (annual) expenditures to meet ERA charges during the period 2015 to 2019 are higher than the corresponding base year forecast. They are based on expenditures recently invoiced by the ERA, with an “uplift” [redacted], in 2015, for additional charges arising in the context of regulator approval of the proposed revisions to the GGP Access Arrangement.

GGT regulatory expenditure is similarly forecast to be higher in 2015, and again in 2019 when work will be required on the next revisions to the Access Arrangement. GGT does not expect its regulatory expenditure “mid cycle” to be as low as was the case in 2012. GGT finds that it is becoming increasingly involved in rule change processes, regulatory reviews, and new regulatory initiatives, all of which require increased staff time and, on occasion, the use of external advisors. GGT expects its next “mid-cycle” expenditure to be [redacted] higher than in 2012.

Carbon liability

A carbon tax, a tax on the release of carbon dioxide and other "greenhouse gases" into the atmosphere, was implemented by the Australian Government in July 2012.

Gas transmission pipelines release carbon dioxide in the exhaust gases from the prime movers driving compressors, from electric power generators, and the flue gas from water bath heaters which heat gas following pressure reduction at pipeline delivery points.

GGT was, therefore required to pay the carbon tax in respect of the operation of the Covered Pipeline from 2012. The tax was repealed, with effect from 1 July 2014, and no expenditure is forecast for the period 2015 to 2019.

Communications equipment lease and maintenance

Expenditure in this subcategory is for the lease and maintenance of electronic communications equipment. This equipment includes equipment for communication, via satellite, of the data generated and used by the SCADA system for the Covered Pipeline, office telephone and data transmission equipment, and cellular telephones.

Forecast expenditure for the period 2015 to 2019 is less than 1% of the operating expenditure forecast for the Covered Pipeline. The annual forecasts are very similar to the (real, December 2013) expenditure for the base year (

Table 26).

Insurance

The cost of insurance attributable to the Covered Pipeline is a portion of the APA Group cost of insuring the assets of its component infrastructure businesses. Corporate insurance includes policies for industrial special risks, public and product liability, fidelity guarantee, motor vehicles, marine transit and workers' compensation.

Insurance costs during the period 2015 to 2019 are $0.697 million a year in real terms (

Table 26), and are similar to the comparable base year figure of $0.715 million.

In May 2014, insurance brokers, Marsh, provided GGT with an estimate of the annual cost of insurance for the GGP as a stand-alone business. That estimate was $0.937 million. The capacity of the Covered Pipeline (measured in TJ MDQ km/d) is approximately 70% of the (covered plus uncovered) capacity of the GGP. Applying this ratio to the Marsh estimate yields an estimate of the insurance cost for the Covered Pipeline. That estimate, $0.656 million, is close to GGT's forecast of $0.697 million, and the latter figure has been retained for the purpose of forecasting operating expenditure for the Covered Pipeline for the period 2015 to 2019.

10.5.4 Corporate costs

The way in which GGT has estimated the corporate costs allocated to the Covered Pipeline is discussed in section 10.7 below.

Corporate costs during the period 2015 to 2019 [redacted]
(

Table 26), [redacted] are significantly lower than the comparable base year figure of $8.209 million. This reduction is a consequence of:

(a) a reduced allocation of APA Group corporate costs to GGP; and

(b) a reduced proportion of GGP corporate costs attributed to the Covered Pipeline.

As discussed in section 10.7, APA Group corporate costs are allocated to entities within the group on the basis of revenues earned. The allocations to the GGP and to the Covered Pipeline were made using revenues earned in 2013. Revenue earned from the GGP in 2013 was a smaller proportion of APA Group revenues than was the case in 2012. There were two principal reasons for this:

(a) in 2012, APA acquired new revenue earning assets, including the South West Queensland Pipeline and the Pilbara Pipeline System, from the Hastings Diversified Utility Fund, and the revenues from these assets contributed to a higher revenue base for corporate cost allocation in 2013; and

(b) revenues from existing operations other than the GGP (including the Moomba to Sydney Pipeline System and the Victorian Transmission System) were higher, in 2013, than they had been in 2012.

Not only was the proportion of corporate costs allocated to the GGP lower than had been the case in 2012. The proportion of GGP corporate costs attributed to the Covered Pipeline for the period 2015 to 2019 was also lower than the proportion of those costs attributed to the Covered Pipeline in 2012.

The proportion used to determine the quantum of GGP corporate costs attributable to the Covered Pipeline is the ratio of TJ km of capacity in the Covered Pipeline to the total TJ km of capacity in the Covered Pipeline and the uncovered pipeline. In 2012 that ratio was about 80%. During the period 2015 to 2019, it is expected to be lower – at approximately 70% - as a result of the increase in the capacity of the uncovered pipeline resulting from GGP expansion in the Pilbara in 2014.

10.6 Major expenditure jobs

As noted earlier, in section 10.3, MEJs are large scale, non-recurrent activities undertaken to maintain the Covered Pipeline. The non-recurrent nature of these activities means that they cannot be assessed using the base year method which has been applied to other components of total operating expenditure.

The MEJs which GGT plans to undertake during the period 2015 to 2019, the reasons for undertaking those activities, and the forecast expenditures are set out in Attachment 10 to the Supporting Information.

10.7 Corporate costs

Although GGT is responsible for the development, operation and maintenance of the Covered Pipeline, the joint venturers intended that the manager would be a small

entity which obtained resources services from the joint venture participants. Resources for the day-to-day operation and management of the GGP are, then, provided by companies within the APA Group. These companies, and GGT itself, are part of a larger corporate group, and rely on the "corporate centre" for the provision of a range of "corporate", or "headquarters", functions. A portion of the costs of providing these corporate functions is attributable to the provision of services using the GGP, and a portion of these costs attributable to the GGP is, in turn, attributable to the provision of pipeline services using the Covered Pipeline.

10.7.1 APA Group corporate functions

Corporate functions which the corporate centre performs for the companies within the APA Group, including GGT, include:

(a) executive management;

(b) company secretarial – including equity raising equity via ASX listing, and raising debt via debt market activity, managing investor relations, quarterly and annual reporting, holding of general meetings, auditing, and the provision of directors' services and general administrative services;

(c) finance and accounting – including, treasury, tax, general financial accounting, general management accounting, financial reporting and the provision of financial services such accounts payable and accounts receivable;

(c) risk management – including insuring the physical assets controlled by APA Group companies, and the development and operation of internal risk management and reporting systems;

(d) human resources management – including recruitment, training, occupational health and safety, compensation and payroll, and industrial relations;

(e) provision of information and communications technology services – including the development and maintenance of company-wide compatible IT systems, and maintaining IT systems security;

(f) legal and regulatory functions – legal services are provided by the General Counsel's office, and economic regulatory services are provided by a corporate Strategy and Regulatory group; and

(g) projects – projects related to business systems and processes which have been identified as increasing efficiency and lowering costs across entities within the APA Group.

10.7.2 A single approach to the allocation of corporate costs

A single approach has been developed for, and is applied in, the allocation of corporate costs across all of the entities within the APA Group.

In this approach, actual corporate costs are allocated across the entities within the Group on the basis of the revenues earned by those entities. Before they are allocated to a particular entity, any of the component costs which have been incurred in the provision of corporate functions which would not be used by that entity are removed.

This single approach is applied to the allocation of corporate costs for:

(a) internal budgeting and performance reporting; and

(b) the forecasting of costs to be used in the setting of prices for regulated assets, (where the allocation corporate costs is likely to be reviewed by the regulator).

The use of a single approach across the APA Group reduces the possibility of the over- or under-estimation of corporate costs where estimates are required for either internal or external purposes.

Furthermore, starting from corporate costs actually incurred ensures that the estimates obtained are grounded in costs which are the outcomes of rigorous review and decision making processes. Within APA Group, budgets prepared for corporate functions, and expenditures made against those budgets, are subject to Board review and approval. The Board must act in the interests of shareholders and, in reviewing and approving the costs of corporate functions, is concerned to ensure that both the budgets, and the costs subsequently incurred against those budgets, are not excessive. Those costs subsequently incurred are then subject to the scrutiny of external audit. The requirements of corporate governance act to ensure that estimates of corporate costs made from corporate costs actually incurred are prudent and efficient.

This revenue based approach to the allocation of corporate costs has been accepted by the AER and ACCC in the context of setting prices for regulated electricity network and gas pipeline system assets owned, wholly or partially, by APA Group. A similar approach was used to establish the allocation of corporate costs used in determining the reference tariff for the last revisions to the GGP Access Arrangement.

10.7.3 Corporate costs attributed to the Covered Pipeline

A proportion of the costs of APA Group corporate functions is attributable to the provision of pipeline services using the Covered Pipeline via the APA Group entities which provide services to GGT. This proportion has been established as follows:

(a) actual corporate costs have been identified from the consolidated – and audited – accounts for APA for the financial year ended 30 June 2013; [redacted];

(b) the actual costs have been allocated, on the basis of revenues earned, to each of the entities within APA Group, including APT Goldfields Pty Ltd, and GGP service providers Southern Cross Pipelines Australia Pty Ltd and Southern Cross Pipelines (NPL) Australia Pty Ltd;

(c) corporate costs attributable to specific projects which are unrelated to GGP service provision (for example, costs of developing solar PV at the Emu Downs Wind Farm) have been excluded;

(d) the total amount allocated to the GGP via allocations to APT Goldfields, Southern Cross Pipelines Australia and Southern Cross Pipelines (NPL) Australia has then been calculated; [redacted];

(f) escalation has been applied to the this total to obtain estimates of corporate costs for each year in the period 2015 to 2019;

(g) the annual estimates of corporate costs obtained in this way are estimates for the GGP; a proportion of each of estimate has been attributed to the Covered Pipeline, the proportion, 70%, being the ratio of TJ km of capacity in the Covered Pipeline to the total TJ km of capacity in the Covered Pipeline and the uncovered pipeline.

10.7.4 Validation of corporate cost allocation

If, as required by rule 91(1), the forecast of operating expenditure used in establishing the total revenue for the Covered Pipeline is to be an estimate of the expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services, then the proportion of corporate costs attributed to GGP reference service provision should be the expenditure of a prudent service provider acting efficiently in accordance with good industry practice to achieve the lowest sustainable cost of delivering that service.

GGT has, therefore, sought to demonstrate that the APA Group corporate costs which have been allocated to the Covered Pipeline are the prudent costs of an efficient service provider by comparing them with the corporate costs of a stand-alone business with a scale of operations similar to that based on the Covered Pipeline. To make this comparison, GGT engaged advisory firm KPMG to estimate the corporate costs of an efficient stand-alone transmission pipeline business with the requisite scale of operations.

KPMG identified the minimum levels of corporate activity required if the stand-alone entity with scale of operations similar to that associated with the GGP were able to function, meeting its commitments to pipeline users, staff and contractors, managing its financial resources, and performing its statutory and regulatory obligations. The costs of carrying out these minimum levels of corporate activity were then obtained using a range of sector and industry cost benchmarks. The choice of these benchmarks was guided by the requirements of rule 91(1) for efficiency, good industry practice and the lowest sustainable cost of providing service.

KPMG concluded that the likely range of corporate costs for a stand-alone business with scale of operations similar to that associated with the GGP, was from $4.539 million per annum to $8.178 million per annum (at December 2013 prices).

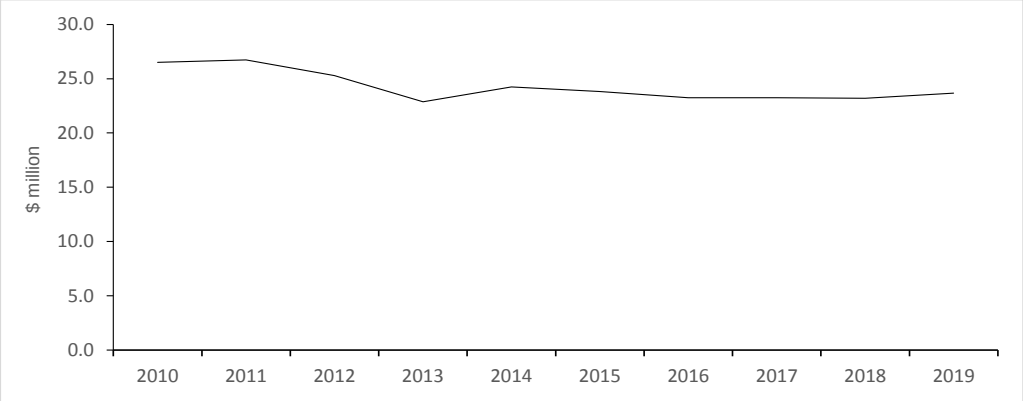
The midpoint of this range, $6.506 million per annum, is higher than the amount of APA Group corporate costs ($6.205 million per annum) attributed to the provision of services using the GGP, and includes in the forecast of operating expenditure used in establishing the total revenue for the pipeline. The difference between the allocation of APA Group corporate costs and KPMG's stand-alone cost estimate indicates the scale economies available when corporate functions are provided across a large corporate group.

KPMG's report is Attachment 11 to the Supporting Information.

10.8 Performance

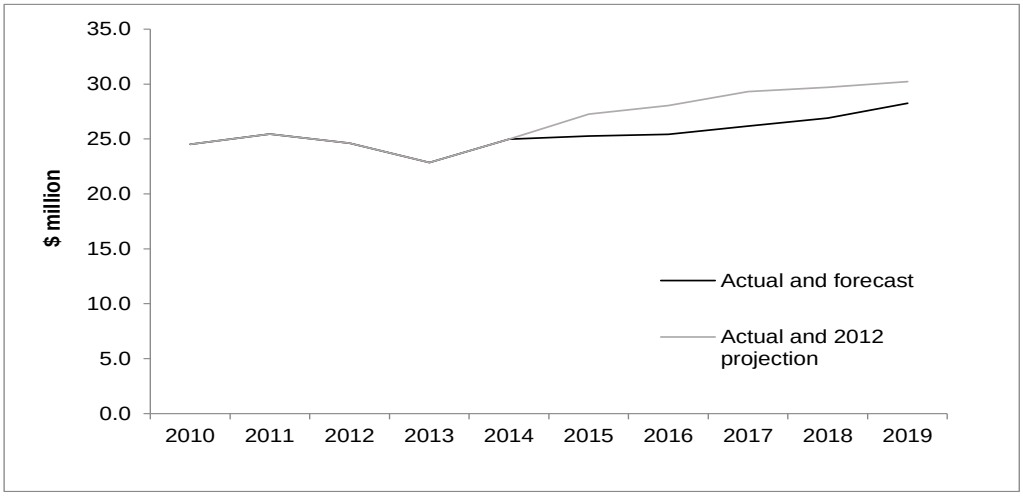
The costs of operating and maintaining the Covered Pipeline increased over the period 2005 to 2009, and have subsequently stabilised. The levelling of (real) annual operating expenditure since 2010 is shown in Figure 10.

Figure 10: Annual operating expenditure ($ December 2013)



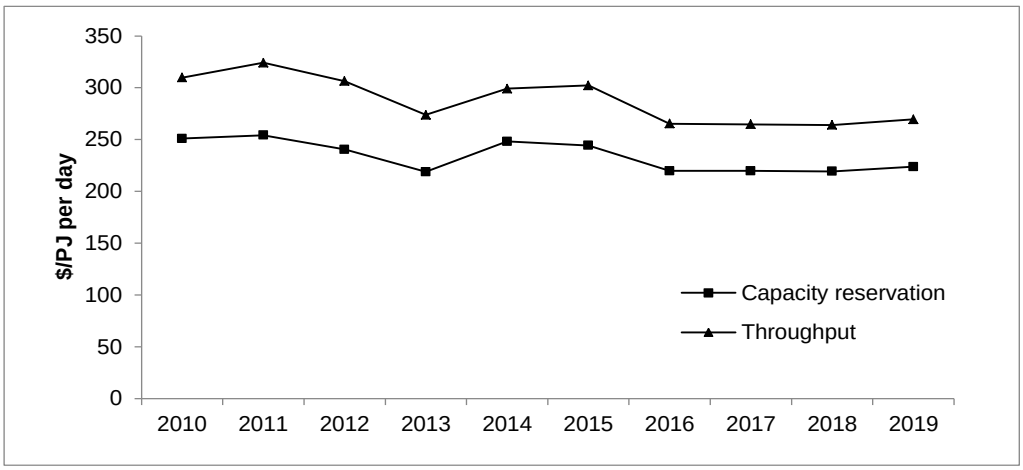
The levelling of costs over the period 2015 to 2019 obscures the significant efficiency improvements which are reflected in the five-year budget for the GGP, and hence in the forecast operating expenditure for the Covered Pipeline. These efficiency improvements are indicated, in by the extent to which the forecast expenditure falls below a simple projection of expenditure in the base year (2012) with escalation of that expenditure at actual and assumed inflation.

Figure 11: Forecast and projected operating expenditures



The level of operating expenditure is a function of Covered Pipeline utilisation. Hence comparisons of unit operating costs are appropriate. Figure 12 shows actual and forecast unit operating costs ($/PJ per day, for capacity reservation and throughput), in real December 2013 dollars, over the period 2010 to 2019.

Figure 12: Unit operating expenditure: $/PJ per day ($ December 2013)



Unit operating costs expressed in $/PJ per day of capacity reservation and/or throughput do not recognise the fact that the Covered Pipeline's outlets are distributed over 78% of its length.

Unit operating expenditure, expressed in $/PJ km per day of capacity reservation and throughput are shown in Figure 13.

Figure 13: Unit operating expenditure: $/PJ km per day ($ December 2013)

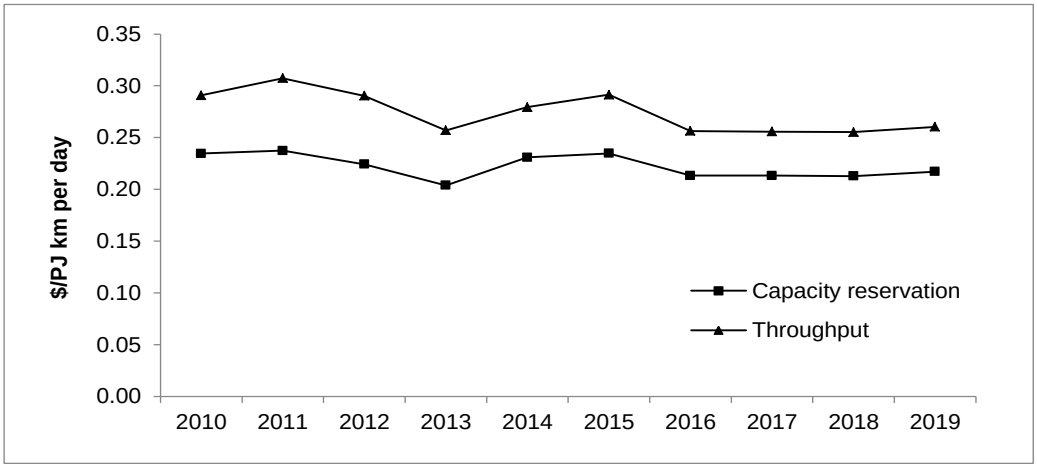
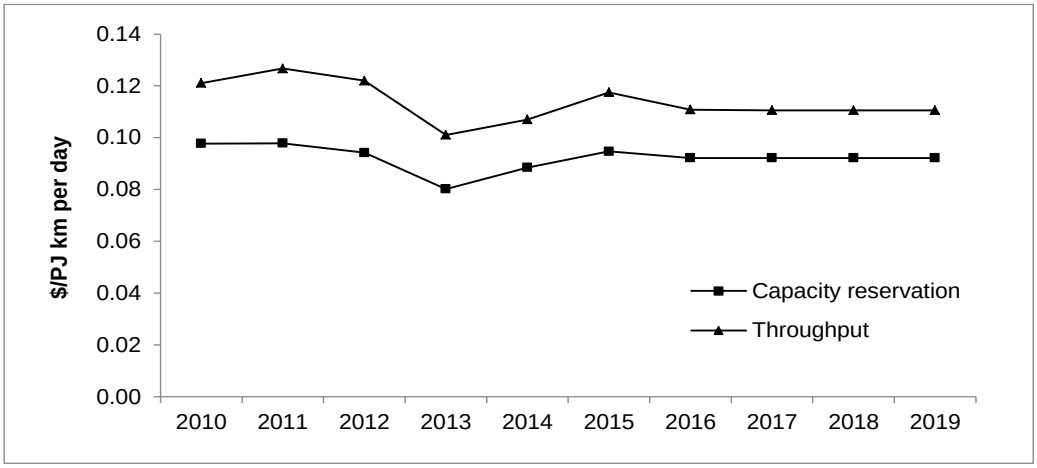


Figure 14. shows similar trends in unit expenditure on engineering and field services (which comprises about 40% of total operating expenditure).

Figure 14: Unit expenditure: engineering and field services: $/PJ km per day ($ December 2013)



Unit operating costs for the period 2015 to 2019 are expected to be lower than in the period 2010 to 2012 (although not as low as in the “abnormal” years 2013 and 2014).

11 Total revenue, proposed revised reference tariff and reference tariff variation mechanism

In preceding sections of the Supporting Information GGT has summarised and explained the way in which it has determined the components of total revenue for the Covered Pipeline.

In this section, GGT:

(a) sets out its calculation of the total revenue, and explains the way in which it has determined the reference tariff for the proposed revised GGP Access Arrangement;

(b) notes the rules governing variation of the reference tariff during the access arrangement period; and

(c) describes the reference tariff variation mechanism of the proposed revised access arrangement.

11.1 Total revenue for the Covered Pipeline

The total revenue for the Covered Pipeline, for the period 2015 to 2019, is summarised in Table 27.

Table 27: Total revenue 2015-2019

	2015	2016	2017	2018	2019
	$ million	$ million	$ million	$ million	$ million
Return on equity	19.474	19.299	18.981	18.515	18.015
Return on debt	18.773	18.604	18.297	17.849	17.366
Depreciation	10.349	10.716	10.906	10.991	11.003
Over-depreciation prior period	-3.211	0.000	0.000	0.000	0.000
Operating expenditure	25.277	25.413	26.168	26.897	28.263
Cost of tax	0.591	3.677	9.994	10.132	10.030
Value of imputation credits	-0.148	-0.919	-2.498	-2.533	-2.507
Total revenue	**71.105**	**76.790**	**81.848**	**81.851**	**82.170**

The return on equity shown in Table 27 has been calculated by multiplying the equity portion (40%) of the projected capital base at the beginning of each year (shown in Table 13 above) by the rate of return on equity component (12.28%) of the proposed allowed rate of return. The return on debt is similarly calculated as the product of the gearing (60%), the projected capital base at the beginning of each year, and the rate of return on debt component (7.89%) of the proposed allowed rate of return.

Depreciation, and the adjustment for over-depreciation at the end of 2014, are as shown above, in Table 10 and Table 12, respectively.

GGT's forecast of operating expenditure for the Covered Pipeline was discussed in the preceding section of the Supporting Information, and the amounts shown in Table 27 are the totals from Table 25 in section 10.

The cost of tax shown in Table 27 has been estimated in the way described in section 8.2. The value of imputation credits in each year of the access arrangement period is the product of GGT's estimate of gamma, 0.25, and the estimated cost of tax. GGT's estimation of gamma was discussed in sections 8.3, 8.4, 8.5 and 8.6 above.

GGT is proposing to offer a single reference service: the Firm Service provided using the Covered Pipeline. There is, therefore, no requirement to allocate the total revenue among multiple services in the process of setting of the reference tariff.

11.2 GGP reference tariff

GGT is proposing to retain the three-part reference tariff which has been in place since the GGP Access Arrangement was approved by the ERA in 2005. This three-part tariff comprises:

(a) toll charge (a price per GJ of contracted capacity (MDQ));

(b) capacity reservation charge (a price per GJ MDQ kilometre); and

(c) throughput charge (a price for GJ kilometre).

The toll charge and the capacity reservation charge are effectively access fees recovering the fixed costs of the Covered Pipeline. The throughput charge recovers variable costs.

By structuring the capacity reservation and throughput charges as distance-related charges, GGT has sought to make the reference tariff reflective of the costs of the resources used to provide pipeline services to individual users at different locations along the GGP.

The reference tariffs in the two preceding access arrangement periods were established assuming allocation of the total revenue to the components of the reference tariff in the proportions shown in Table 28.

Table 28: Allocation of total revenue to reference tariff components

	Proportion
Toll charge	11.3%
Capacity reservation charge	72.2%
Throughput charge	16.5%

GGT has examined the mix of fixed and variable costs in the total revenue for the period 2015 to 2019, and has elected not to change the proportions shown in the table.

The toll charge of the proposed reference tariff has been calculated as the price during the period 2015 to 2019 which sets the present value of the forecast revenue from the charge equal to 11.3% of the present value of the total revenue. For tariff calculation, the forecast revenue has been calculated using the forecast of MDQ shown in Table 1 above. The discount rate used in calculating the present values of the forecast revenue and the total revenue is the proposed allowed rate of return (9.64%).

Similarly:

(a) the capacity reservation charge has been calculated as the price during the period 2015 to 2019 which sets the present value of the forecast revenue from the charge equal to 72.2% of the present value of the total revenue; and

(b) the throughput charge has been calculated as the price during the period 2015 to 2019 which sets the present value of the forecast revenue from the charge (determined using the throughput forecast of Table 1) equal to 16.5% of the present value of the total revenue.

The proposed revised reference tariff for the Covered Pipeline is shown in Table 29.

Table 29: Proposed revised reference tariff

Toll charge	$/GJ MDQ	0.235806
Capacity reservation charge	$/GJ MDQ km	0.001459
Throughput charge	$/GJ km	0.000442

The reference tariff is to vary over the course of the access arrangement period in accordance with the reference tariff variation mechanism of the proposed revised GGP Access Arrangement. The rationale for this reference tariff variation mechanism is set out in the next section of the Supporting Information.

11.3 Reference tariff variation mechanism

The reference tariff variation mechanism in the GGP Access Arrangement is a variation mechanism which satisfied the requirements of the Code. GGT proposes to revise the mechanism so that it now accords with the requirements of the NGR.

In this section of the Supporting Information we note the rules which govern the reference tariff variation, and set out the rationale for the mechanism of the proposed revised access arrangement.

11.3.1 Rules governing the reference tariff variation mechanism

Rule 92(1) requires that a full access arrangement include a mechanism (reference tariff variation mechanism) for variation of a reference tariff over the course of an access arrangement period.

The reference tariff variation mechanism may provide for variation of the reference tariff:

(a) in accordance with a schedule of fixed tariffs (rule 97(1)(a));

(b) in accordance with a formula set out in the access arrangement (rule97(1)(b));

(c) as a result of a cost pass through for a defined event (rule 97(1)(c)); and

(d) by a combination of (a) to (c) above (rule 97(1)(d)).

Rule 97(2) states that, where reference tariff variation is by a formula, the formula may provide for:

(a) variable caps on the revenue to be derived from a particular combination of reference services;

(b) tariff basket price control;

(c) revenue yield control; or

(d) any combination of (a) to (c).

The mechanism itself must also provide for the ERA's adequate oversight or powers of approval over variation of the reference tariff (rule 97(4)).

In deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the ERA must, in accordance with rule 97(3), have regard to:

(a) the need for efficient tariff structures;

(b) the possible effects of the reference tariff variation mechanism on the administrative costs of the regulator, the service provider, and users or potential users;

(c) the regulatory arrangements (if any) applicable to the relevant reference services before the commencement of the proposed reference tariff variation mechanism; and

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction).

The ERA may also have regard to any other relevant factor in deciding on the appropriateness of a particular reference tariff variation mechanism (rule 97(3)(e)).

11.3.2 GGP reference tariff variation mechanism

The reference tariff variation mechanism of the proposed revised GGP Access Arrangement comprises two parts:

(a) a scheduled reference tariff variation mechanism; and

(b) a cost pass-through variation of the reference tariff.

The scheduled reference tariff variation mechanism further provides for:

(a) quarterly scheduled variation of the reference tariff; and

(b) annual scheduled variation of the reference tariff.

Quarterly scheduled variation of the reference tariff

The proposed quarterly scheduled variation mechanism replicates the quarterly tariff variation mechanism which is in clause 9.8 of the General Terms and Conditions in Appendix 3 to the GGP Access Arrangement. The quarterly variation mechanism has been moved from the Terms and Conditions to Schedule A of the proposed revised GGP Access Arrangement.

The quarterly scheduled variation of reference tariffs of the proposed revised access arrangement has the same effect as the equivalent provision in the GGP Access Arrangement. It replaces, at the commencement of each quarter, the inflation which was assumed for reference tariff determination, with a measure of actual inflation obtained from the change in the Consumer Price Index six months prior, and varies the reference tariff accordingly.

Annual scheduled variation of reference tariff

The annual scheduled reference tariff variation mechanism of the proposed revised GGP Access Arrangement is similar in design to the reference tariff adjustment mechanism of Schedule 1 to the GGP Access Arrangement.

Its operation, at the commencement of each year during the access arrangement period:

(a) effects the quarterly inflation adjustment of the reference tariff, in place of adjustment in accordance with the quarterly scheduled variation of reference tariffs;

(b) allows GGT flexibility to vary the individual components of the reference tariff, by up to 2.0%, within a constraint on the overall revenue which might be earned at the reference tariff (the weighted average tariff basket);

(c) effects the a change in the reference tariff following annual adjustment of the return on debt in the way proposed in the ERA's Rate of Return Guidelines; and

(d) provides for recovery, through a varied reference tariff, of regulatory costs which were unanticipated, and not taken into account in tariff determination at the time the revisions to the GGP Access Arrangement were approved.

Three of these components of the annual scheduled reference tariff variation mechanism are components of the reference tariff adjustment mechanism of Schedule 1 to the GGP Access Arrangement.

GGT has added to these three a fourth component which has the effect of annually updating, during the access arrangement period, the return on debt used in reference tariff determination. If the return on debt is estimated using a trailing average approach, with annual updating, then rule 87(12) requires that the resulting change to the service provider's total revenue is to be effected automatically through the application of a formula. As discussed earlier, in section 7.8.4, GGT is proposing a trailing average approach to estimation of the return on debt for the Covered Pipeline, and the annual updating of the estimate of the return on debt (and not just of the debt margin) obtained by applying that approach. GGT has incorporated into the annual scheduled variation of reference tariffs the variation of total revenue in accordance with the requirement of rule 87(12), and the change to the reference tariff implied by that change in total revenue.

Regulator oversight of scheduled reference tariff variation

Sections 8.3B to 8.3H of the Code set out a process through which a service provider notified the regulator of a proposed reference tariff variation, and the regulator responded to the notice, either allowing or disallowing the variation. There are no equivalent provisions in the NGR, and GGT has sought to retain consistency with the process which applied earlier by incorporating much of the process which was in the Code into text of the proposed revised GGP Access Arrangement.

GGT's submission of a scheduled reference tariff variation notice is to follow the process which applied under the Code, and the process and timelines for ERA assessment and allowance, or disallowance, of the tariff variation proposed in the notice are as they were in the Code.

Cost pass-through variation of reference tariff

The cost pass-through reference tariff variation mechanism of the proposed revised GGP Access Arrangement is similar to the "adjustment for changes in imposts" mechanism of clause 5.4 of the GGP Access Arrangement. As before, the purpose of the mechanism is to ensure that costs resulting from material unforeseen or uncontrollable events affecting provision of the reference service can be recovered through the reference tariff. Those unforeseen or uncontrollable events are, however, limited to events in a number of classes defined in the access arrangement.

GGT has included, in the proposed revised GGP Access Arrangement, the following defined events in respect of which costs may be "passed through" to a reference tariff variation:

(a) an insurance cap event;

(b) an insurer credit risk event;

(c) a natural disaster event;

(d) a regulatory change event;

(e) a service standard event;

(f) a tax change event; and

(g) a terrorism event.

The occurrence of any of these events is beyond GGT's control and is likely to cause GGT to incur costs in the provision of the reference service for which it is not otherwise compensated, either through the (unvaried) reference tariff or through any other mechanism in the GGP Access Arrangement.

The defined events now included in the cost pass-through variation mechanism are based on those previously approved by the AER in access arrangements for the Amadeus Gas Pipeline, the Roma Brisbane Pipeline and the Victorian Transmission System. Unlike these access arrangements, the proposed revised GGP Access Arrangement does not include a carbon cost event in the list of cost pass-through events. Any further impost related to carbon pricing is to be addressed through the regulatory cost factor of the annual scheduled reference tariff variation mechanism.

Reference tariff variation consequent upon occurrence of one of the defined events is subject to any change, or expected change, in the cost of providing the reference service across the remaining years of the access arrangement period exceeding a specified materiality threshold of 0.5% of total revenue of the Covered Pipeline in the year in which the event first occurs.

Regulator oversight of cost pass-through tariff variation

Regulator oversight of the cost-pass through reference tariff variation mechanism of the GGP Access Arrangement relies on the notice and approval process of sections 8.3B to 8.3H of the Code. GGT has, therefore, incorporated into the cost pass-through variation clause of the proposed revised access arrangement much of the process which was in the Code.

Rule 97(3): matters to which the ERA must have regard

The quarterly variation mechanism varies the reference tariff so that it more closely reflects variations in the costs which the tariff is to recover, at least to the extent that those cost variations are the result of changes in the general level of prices. The quarterly tariff variation mechanism is intended to maintain efficient cost recovery during the access arrangement period. It is an appropriate mechanism when regard is had to the need for efficient tariff structures (rule 97(3)(a)).

Similarly, the annual variation mechanism varies the reference tariff so that it more closely reflects variations in the costs which the tariff is to recover. The annual scheduled variation mechanism is intended to maintain efficient cost recovery during the access arrangement period. It is an appropriate mechanism when regard is had to the need for efficient tariff structures (rule 97(3)(a)).

Variation of the reference tariff to take into account changes in the costs of providing the reference service attributable to certain defined events also ensures the tariff more closely reflects the costs which it is to recover. The cost pass-through variation mechanism is intended to maintain efficient cost recovery during the access

arrangement period, and is an appropriate mechanism when regard is had to the need for efficient tariff structures (rule 97(3)(a)).

GGT has incorporated into the proposed revised GGP Access Arrangement, for both the scheduled reference tariff variation mechanism and the cost-path through mechanism, much of the process which was in the Code for notification and regulator oversight of reference tariff variation. Not only does this comply with the requirements of rule 97(4). The proposed continued use of an established and familiar process should reduce the administrative costs of both the ERA and GGT (rule 97(3)(b)).

The results of reference tariff variation in accordance with the scheme of the proposed revised GGP Access Arrangement should be readily verifiable by third parties, and the administrative costs of users and prospective users of the Covered Pipeline should not be increased (rule 97(3)(b)).

This maintenance of continuity in the form of the reference tariff variation mechanism, and in the processes through which it is given effect, has regard for the regulatory arrangements applicable to the GGP reference service before the commencement of the proposed variation mechanism (rule 97(3)(c)).

Some of the users deliver into the Covered Pipeline gas which has been transported through the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The scheme of reference tariff variation in the proposed revised GGP Access Arrangement is similar in form to the scheme in the DBNGP Access Arrangement. The DBNGP Access Arrangement includes annual, but not quarterly, variation of the reference tariff for changes in inflation as measured by changes in the Consumer Price Index, and a mechanism for the pass-through, to varied reference tariffs, of unanticipated taxes and the costs of unanticipated and uncontrollable (by the service provider) events. There is, then, at least in respect of tariff variation during an access arrangement period, consistency between regulatory arrangements for similar pipeline services within Western Australia (rule 97(3)(d)).

The location of the GGP is such that its interconnection with pipelines in other jurisdictions is extremely unlikely in the foreseeable future. There is no compelling requirement for the reference tariff variation mechanism of the proposed revised GGP Access Arrangement to be consistent with regulatory arrangements for similar services in other jurisdictions.

Attachments

Attachment 1:	Log of changes to GGP Access Arrangement
Attachment 2:	HoustonKemp Economists, *Methodology for Allocating Goldfields Gas Pipeline Costs*, June 2014
Attachment 3:	Tom Hird, CEG (Competition Economists Group), *Cost Allocation for the Goldfields Gas Pipeline*, June 2014
Attachment 4:	HoustonKemp Economists, Depreciation *Methodology for the Goldfields Gas Pipeline*, 12 August 2014
Attachment 5:	Conforming capital expenditure: 2010-2014
Attachment 6:	Forecast conforming capital expenditure: 2015-2019
Attachment 7:	SFG Consulting, *Cost of equity for the Goldfields Gas Pipeline: Report for Goldfields Gas Transmission*, July 2014
Attachment 8:	SFG, *Alternative versions of the dividend discount model and the implied cost of equity: Report for Jemena Gas Networks, ActewAGL, APA, Ergon, Networks NSW, Transend and TransGrid*, 15 May 2014
Attachment 9:	Operating expenditure over earlier access arrangement period: auditor review reports
Attachment 10:	Major expenditure jobs: 2015-2019
Attachment 11:	KPMG, *Corporate Cost Benchmarking: Goldfields Gas Pipeline*, June 2014