APA Group

APT Petroleum Pipelines Limited

Access Arrangement Submission

Effective
12 April 2012 – 30 June 2017

Confidentiality note:
This document contains information
regarding the commercial operations
of particular shippers.
This information has been redactedin this edition.

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1 Introduction

This submission provides supporting information for APT Petroleum Pipelines Pty Limited (APTPPL)'s proposed revision of the Access Arrangement for the Roma Brisbane Pipeline (RBP) to be effective from 12 April 2012.

In accordance with the requirements of section 132 of the National Gas Law (NGL) and section 43(1) of the National Gas Rules (NGR), APTPPL has provided to the Australian Energy Regulator (AER) with this submission:

- Revisions to the access arrangement applying in respect of the RBP; and
- An Access Arrangement Information document.

Together these documents make APTPPL's access arrangement revision proposal.

1.1 Requirements for access arrangement revision proposal

1.1.1 Information required by the National Gas Law and Rules

With the commencement of the National Gas Law on 1 July 2008, the AER assumed the role of economic regulator for covered (that is, regulated) transmission pipelines in all states and territories (except Western Australia). The NGL has been enacted in these jurisdictions via mirror legislation. The NGR forms a schedule to the legislation and has the force of law.

Distribution and transmission pipelines covered under the former National Gas Code immediately before the commencement of the NGL are deemed to be covered pipelines under the NGL.[1] The NGL also specifies that current access arrangements, approved or drafted and approved by a relevant regulator under the National Gas Code, are deemed to be full access arrangements approved or made by the AER under the NGL.

The provisions at Schedule 3 of the NGL and Schedule 1 of the Rules apply to the RBP since the earlier access arrangement falls under these provisions within the definition of a transitional access arrangement.

The General savings provisions of the NGL state that the repeal of the National Gas Code does not affect "the previous operation of the old access law or Gas Code or anything suffered, done or begun under or in accordance with the old access law or Code".[2]

[1] NGL, schedule 3, sections 6 and 7
[2] NGL, Schedule 3, section 3

Under the Transitional provisions of the NGL, sections 3, 8 and 10.8 of the National Gas Code "continue to apply to a transitioned access arrangement" until revisions to that access arrangement take effect.[3]

APTPPL has prepared its access arrangement revision proposal in accordance with applicable law, including the transitional provisions set out in the NGL.

The NGL and Rules set out detailed requirements for information to be included in an access arrangement revision proposal and associated access arrangement information. Where relevant, these requirements are referenced throughout this submission. APTPPL has also provided an Index at Appendix C of this submission which includes guidance on where requirements under the Rules can be found in the revision proposal.

1.1.2 Information required by Regulatory Information Notice

On 26 September 2011, the AER served on APTPPL a Regulatory Information Notice (RIN) under Division 4 of Part 1 of Chapter 2 of the NGL. The RIN specifies information to be provided to the AER by APTPPL in its access arrangement revision proposal, and the form of that information.

This submission, along with the access arrangement proposal, access arrangement information, and accompanying financial models, provides information in satisfaction of the requirements placed on APTPPL in the RIN.

The RIN also requires that APTPPL submit to the AER an Index of Information outlining where the information to be provided under the RIN is contained in the access arrangement revision proposal. This Index of Information can be found at Appendix C to this submission.

1.1.3 Basis of information in the access arrangement revision proposal

Rule 73 states that:

(a) Financial information must be provided on:

(i) a nominal basis; or

(ii) a real basis; or

(iii) some other recognised basis for dealing with the effects of inflation.

[3] NGL, Schedule 3, section 30. Section 3 of the National Gas Code related to the content of an access arrangement, section 8 governs reference tariff principles, and section 10.8 contains definitions.

(b) The basis on which financial information is provided must be stated in the access arrangement information.

(c) All financial information must be provided, and all calculations made, consistently on the same basis.

Unless otherwise stated, all information in the access arrangement revision proposal is provided in real 2011/12 dollars. Past values are brought to this basis using the Consumer Price Index (CPI) all groups, eight capital cities average June over June published by the Australian Bureau of Statistics (ABS).

1.2 Corporate structure

APT Petroleum Pipelines Pty Limited (APPPL) is wholly owned by APT Pipelines Limited. This structure is shown in Figure 1.1 below.

Figure 1.1: APTPPL Corporate ownership structure

Company	Activity
APT Pipelines Limited ACN 009 666 700 (Australian Public Company)	Parent investment company for Australian Pipeline Trust.
Owns 100% of:	
Sopic Pty Limited ACN 010 851 288 (Australian Private Company)	Owns shares in APT Petroleum Pipelines Holdings Pty Limited.
Owns 100% of:	
APT Petroleum Pipelines Holdings Pty Limited ACN 009 738 489 (Australian Private Company)	Owns shares in APT Petroleum Pipelines Limited.
Owns 100% of:	
APT Petroleum Pipelines Pty Limited ACN 009 737 393 (Australian Private Company)	Owns and operates Roma to Brisbane Pipeline including Peat Lateral

APTPPL is both owner and operator of the RBP. APTPPL is not a local agent of a service provider of the pipeline as defined by the NGL, nor does it act on behalf of another service provider of the pipeline as defined by the NGL.

APTPPL's sole business is the ownership and operation of the RBP. APTPPL has no associate contracts in place relevant to the delivery of pipeline services for the RBP.

1.3 Pipeline history and characteristics

The RBP was commissioned in its original configuration in 1969. It now consists of a mainline, which is both compressed and looped, and three lateral pipelines; Peat lateral, connecting it to CSM gas sources near Peat and Scotia, Swanbank Lateral, feeding into Swanbank Power Station and Lytton Lateral, supplying the Caltex Refinery. The mainline is approximately 440 km long with about 30 km of its length running through Brisbane to Gibson Island.

The original 410 km section from Wallumbilla to Ellengrove is 273 mm in diameter (DN250). This section is looped with a 406 mm diameter pipeline (DN400). The looping was carried out in several stages, between 1988 and 2002, after the original line had been fully compressed.

The Swanbank lateral was completed in 2001 and is 38 km long with a current capacity 52TJ/day. The Peat lateral was completed in the same year (the Scotia extension was completed in 2003) and is 121 km long with a current nominal capacity of 74 TJ/day. The Peat lateral became part of the covered pipeline on 1 January 2006 after APTPPL elected, following consultation with the ACCC (as permitted by its access arrangement), for it to be covered. The 6km Lytton lateral was completed in 2010.

Under the current access arrangement for the RBP, the reference service and reference tariff apply to the existing capacity as configured at 31 January 2006 of 204 TJ/day and any expansions that are covered. The capacity of the pipeline as currently configured (including the location of receipt points and loads) is approximately 219 TJ/day. The current nominal licensed capacity of the pipeline is 300 TJ/day. Volumes during the proposed access arrangement period are expected to grow in line with the Metropolitan Loop expansion to 232TJ/day.

The pipeline originally supplied the Brisbane area with gas from Surat Basin fields close to Roma. In 2001 and 2002 the RBP was extended via the Peat Lateral to enable Coal Seam Methane (CSM) from the Peat and Scotia gas fields to be supplied into south-east Queensland. The RBP also connects with the Queensland Gas Pipeline (QGP)[4], which runs from Wallumbilla to Rockhampton (via Gladstone). This allows Wallumbilla to function as a hub for the supply of gas in Queensland. Natural gas is no longer sourced from the Cooper/Eromanga Basin via the Epic Energy owned South West Queensland Pipeline (SWQP), due to changes to flow in this pipeline.

[4] Currently owned by SPI (Australia) Assets Pty Ltd

There are six compressor stations along the length of the pipeline. Those at Yuleba, Kogan and Oakey serve the original pipeline while those at Condamine, Dalby and Gatton serve the looped pipeline.

The expansions of RBP capacity and the construction of the Lateral pipeline occurred in response to market growth, and were underpinned by contracts negotiated with third parties such as producers, power stations, gas utilities and major industrial customers. The RBP currently receives gas from numerous receipt points and delivers gas to numerous delivery points. Additional receipt and delivery points have been added from time to time.

Dates in the history of the expansion of the RBP are shown below in Table 1.1.

Table 1.1: RBP Key Dates

Year	Event
1965	Incorporated as Associated Pipelines Limited.
1969	Pipeline construction completed. Associated Pipelines Limited sells bundled gas and pipeline services and has related ownership with upstream gas fields.
1982	Dalby Compressor installed, Kogan Compressor installed.
1983	Oakey Compressor installed.
1984	Condamine Compressor installed.
1985	Yuleba Compressor installed.
1986	Gatton Compressor installed.
1987	Joint Venture established. 85% interest held by Associated Pipelines Limited. 15% interest sold to I.O.L. Petroleum Limited.
1988	Looping 1 completed. Associated Pipelines Limited name changed to CSR Petroleum Pipelines Limited. Acquisition of CSR Petroleum Pipelines Limited by The Australian Gas Light Company, as part of a larger acquisition of CSR's oil and gas production and transportation operations. This included the acquisition of gas production interests in Qld. CSR Petroleum Pipelines Limited name changed to AGL Petroleum Pipelines Limited.
1990	Looping 2 completed.
1993	Upstream gas production interests sold by AGL.
1997	IOL Petroleum Limited change of name to Interstate Pipelines Pty Limited.

1998	Looping 3 completed.
2000	Looping 4 completed. AGL divestment of its pipelines group includes AGL Petroleum Pipelines Limited through float of Australian Pipeline Trust. AGL Petroleum Pipelines Limited change of name to APT Petroleum Pipelines Limited (APTPPL).
2001	Peat Lateral and Swanbank Lateral completed Acquisition of Interstate Pipeline's 15% interest by APTPPL.
2002	Looping 5 & 6 completed.
2003	Scotia extension to Peat Lateral completed.
2010	Lytton Lateral completed.

Management and operation of the RBP pipeline includes:

- Scheduling and control of the gas haulage through the pipelines through control rooms
- Planning, scheduling, prioritising of labour, materials and supplies required to operate and maintain all assets
- Providing operational input into asset management, commercial development, regulatory management and compliance activities relating to the assets under management
- Providing emergency response, safety management and repair response for APTPPL's assets
- Planning and delivery of small scale asset capital replacement and development projects
- Providing support in construction and commissioning of new projects

Urbanisation and Encroachment

In accordance with AS2885.3, pipelines must be designed to specifications determined by, amongst other things, the existing, surrounding land use. Existing land use determines key pipeline specifications such as depth of coverage and wall thickness of pipeline.

The failure of a high pressure pipeline can impact an area several hundreds of metres from a pipeline. A frequent cause of pipeline failure worldwide is caused by construction or maintenance activities. Australian high pressure pipelines are

designed, operated and maintained to mitigate threats that have the potential to cause failure.

The existing RBP pipeline was designed taking into account the plans that existed at the time it was constructed. When commissioned in 1969, the RBP had been constructed through mainly rural or semi-rural areas with low density population. With population growth, development and transformation of land use, the urbanisation of south east Queensland continues to impact on pipeline operations.

Although APTPPL must comply with changing planning and technical regulations, there is currently no requirement on local governments or developers to ensure that APTPPL are consulted with respect to the potential impacts of land use changes or developments in the vicinity of the pipeline and its operation. This has resulted in inappropriate planning outcomes such as the construction of residential housing adjacent to high pressure pipeline easements.

With these changes come increased public encroachment upon the pipeline right of way, resulting in increased operations costs through increased Dial Before You Dig (DBYD) inquiries, observation of external party works, patrolling costs and public education initiatives.

1.4 Changes to the access arrangement

APTPPL has revised the RBP access arrangement to apply in the coming access arrangement period. Key revisions made to the earlier access arrangement relate to:

- The move from the National Gas Code to the Rules;
- The introduction of a Short Term Trading Market hub in Brisbane;
- Alignment of access arrangement structure in line with other APA Group access arrangements; and
- The adoption of terms and conditions that are more in line with recent gas transportation agreements.

APTPPL has also revised the extensions and expansions policy, the queuing policy, and added a capital redundancy policy. These changes are discussed in the following sections.

1.4.1 General changes

APTPPL's previous access arrangement has been revised to be consistent with the National Gas Rules. Revisions to the access arrangement are largely associated with the adoption of new terms used in the Rules, however some further revisions

are required to comply with new requirements, for example in relation to capacity trading and the Short Term Trading Market.

APTPPL has also updated the access arrangement to reflect the current form of APA Group access arrangements, and revised terms and conditions.

Revisions to the main body of the access arrangement, and the reasons for those changes, are set out in Attachment A.

APTPPL considers that its revisions to the access arrangement are necessary, and that they are consistent with the National Gas Objective as they either reflect changing regulatory requirements, or bring the RBP access arrangement into alignment with other APA Group access arrangements. The benefits of this alignment are discussed further in the following section.

1.4.2 Access arrangement terms and conditions

APTPPL is owned by the APA Group, which also owns a number of other regulated and unregulated gas assets across Australia. These assets have in place existing access arrangements and gas transportation agreements which in many cases reflect outdated or redundant contracting practices, or contain unnecessary variations to core terms and conditions. These inconsistencies across assets add to APA Group's costs as an operator of multiple gas assets and limit its ability to access the full benefits that can arise from economies of scale in owning multiple gas assets.

To address these issues, APA Group is implementing a standard form Gas Transportation Agreement across the all assets in the Group, which is also reflected in the terms and conditions of various access arrangements for covered pipelines.

APA Group first proposed these standard form terms in respect of the Amadeus Gas Pipeline (AGP) access arrangement revision process. As part of that public process, the AER undertook a comprehensive review of those provisions, with submissions made by a number of large national users of pipeline services. As a result of that review, a number of changes were made to the standard form provisions.

Recognising the significant benefits that APA Group derives from consistent arrangement, APTPPL has in large part incorporated the terms and conditions approved by the AER in respect of the AGP into the RBP access arrangement. Variations to the terms and conditions approved by the AER for the AGP are limited to changes necessary to:

- Support the STTM hub in Brisbane, and other Queensland-specific matters;
- Incorporate authorised overruns into the access arrangement;
- Support the specific Services offered under the RBP access arrangement;

- Accommodate the two gas quality specifications in place for the pipeline;
- Address unacceptable changes to the liability and force majeure clauses imposed by the AER in respect of the AGP AA; and
- Revise Assignment clauses that have proven unworkable in practice.

APTPPL has included in the access arrangement the APG AA terms and conditions as approved by the AER and marked material changes to that version in the accompanying "marked-up" version of the access arrangement. A detailed description of each part of the new terms and conditions, as well as reasons for the variations to the AGP AA discussed above, is provided in Appendix B to this submission. The information provided on interpretation of clauses is for explanatory purposes and is provided to assist in the review process.

APTPPL considers that the revised terms and conditions are necessary and that they are consistent with the National Gas Objective. The terms and conditions as proposed support a number of regulatory obligations imposed on APTPPL (such as the STTM), and well as provide necessary commercial protections for APTPPL and Users in the provision of the firm service.

APTPPL also considers that there are considerable benefits potentially available to APTPPL, and to APA Group more broadly, in adopting consistent terms across its gas transportation agreements. These largely arise from lower legal drafting and advice costs, and in improvements in the business-wide understanding of contracting arrangements in place for particular pipelines and users.

Users and prospective users will also benefit from consistency in contracting arrangements across APA Group's assets (where that consistency is possible and appropriate given the specific circumstances of the pipeline) as many users are common across a number of APA Group assets in different states and territories. These users are likely to benefit from lower administrative and legal costs associated with understanding and complying with gas transportation arrangements.

Consistent terms and conditions are also necessary to support APA Group's one-APA vision for the delivery of pipeline services across an east coast grid, as embodied in APA Group's "Project Colin" IT project.

1.4.3 Revisions submission and commencement dates

APTPPL proposes a five year access arrangement period. Consistent with Rule 50(1), APTPPL proposes to include an access arrangement revisions submission date of 1 July 2016. This date provides the AER with a 12 month revision period, consistent with the general rule.

1.4.4 Extensions and Expansions

Rule 104 specifies that the extensions and expansion policy must state whether the applicable access arrangement will apply to incremental services provided as a result of a particular extension or expansion.[5]

1.4.4.1 *Extensions*

APTPPL's former extensions and expansions policy gave the discretion to the service provider to determine whether an extension would be part of the covered pipeline. Where an extension was covered, access to services was to be provided as a negotiated service at a negotiated tariff.

Recent AER decisions in respect of gas pipelines and networks reflect a change in approach, whereby the AER has not approved extension and expansion policies that grant this discretion to the service provider. Instead, the AER has imposed a process on the service provider whereby the service provider must apply to the AER for a decision on whether the extension will be covered by the access arrangement.

APTPPL does not support this approach as it does not consider that it is consistent with the NGL or NGR.

Under the National Gas Access Regime, there is a clear process for a pipeline to become covered, as specified in the National Gas Law, starting at section 92. This process requires an application to the National Competition Council (NCC), an assessment against clear coverage criteria, and a recommendation to the relevant Minister for ultimate decision.

The purpose of the extensions and expansions policy is to provide an administrative "shortcut", to allow the service provider the option to voluntarily elect for any extensions or expansions to a covered pipeline to also be covered under the National Gas Access Regime.

In the construct of the Rules, the process is that if the Service Provider's extensions and expansions policy specifies whether the access arrangement will apply to services provided by the extension or expansion, and then it is included as part of the covered pipeline under the administrative shortcut provisions in section 18 of the NGL.

The process then, is for the service provider to elect that the access arrangement will apply, and that election leads to coverage.

Where the extensions and expansions policy does not provide for the access arrangement to apply to services provided by the extension or expansion, then the provisions of NGL section 18 do not become operative. In this case, a decision on

[5] Rule 104(1)

coverage must be made by the relevant Minister following a recommendation from the NCC under NGL section 95.

APTPPL considers that, within the framework of the National Gas Law and the Australian Energy Market Agreement, matters relating to coverage of natural monopoly infrastructure rests squarely with the NCC. It is therefore beyond powers for the AER to place itself in the position of deciding whether an asset should be covered or not.

Notwithstanding these concerns, APTPPL has proposed an extensions policy that is consistent with that approved by the AER in respect of the AGP access arrangement. This policy applies to extensions that are not included in forecast conforming capital expenditure, meaning that their costs are not included in the Reference Tariff.

Where APTPPL extends the pipeline and the AER determines that the access arrangement will apply to that extension, APTPPL will elect whether access to incremental Services provided through that extension will be offered as part of the reference service at the reference tariff, or as a negotiated service at a negotiated tariff.

1.4.4.2 *Expansions*

Similar to APTPPL's approach to extensions, expansions will be covered by the access arrangement unless the AER agrees that they will not be covered. Where an expansion is covered, the service provider can elect whether incremental services provided by that expansion are offered as part of the reference service at the reference tariff, or as a negotiated service at a negotiated tariff.

This approach is identical to the approach approved by the AER in respect to the AGP access arrangement, with the exception of the inclusion of clause 7.2(d) that makes clear that the expansions provisions do not apply to the extent that the costs of the expansion above the existing capacity has already been included and approved by the AER in the calculation of reference tariffs. APTPPL considers that his change makes explicit this part of the operation of the extensions and expansions policy.

1.4.4.3 *Fixed principles*

The extension and expansion provisions provide that where an extension or expansion is offered at a negotiated tariff, the capital investment, operating costs and demand associated with incremental services offered as a negotiated service will not be considered in the calculation of the reference tariff. APTPPL has proposed that this provision be a fixed principle for 15 years.

This period of certainty is essential to support the investment in a negotiated service.

Without this protection, the AER could determine in the following access arrangement that the incremental services provided by the extension are part of the reference service. This would mean that the incremental services would need to be offered at the reference tariff. For pipeline extensions offered as negotiated services, this outcome is unlikely to provide sufficient return to APTPPL for that investment. To address this risk, APTPPL would need to ensure that it recovered all of the incremental cost of the extension (that which would not be recovered at the reference tariff) in the remaining years of the existing access arrangement. This is likely to increase costs of extensions to prospective users of those services, thereby undermining incentives to invest in the pipeline. Alternatively, APTPPL would not proceed with the extension.

APTPPL does not consider that these outcomes would be consistent with the National Gas Objective as they would not promote the efficient use, of and investment in, the pipeline for the long term interests of consumers.

The AER considered and rejected the inclusion of a similar fixed principle in respect of the AGP access arrangement.[6] The AER stated that its reasons for rejecting this fixed principle were that:

- There is merit in monitoring the operation of NT Gas's extensions and expansions policy and that the policy may need to be amended to ensure it operates to fulfil the requirements of r.104 of the NGR. Inclusion of the fixed principles would prevent such changes;

- The perceived risk presented by NT Gas was slight as, where NT Gas negotiates with a user to extend the pipeline on the basis of a negotiated tariff, the AER would take this into account at the next access arrangement review; and

- The inclusion of fixed principles is not a necessity for such negotiations and they would cause inflexibility in the extensions and expansions requirements.

APTPPL considers that these reasons underestimate the impact of risk on efficient investment in the pipeline, and undermine the intent of fixed principles within the access arrangement.

The AER's conclusion that the risk to NT Gas is slight is based on an assertion that it would "take into account" that an extension was provided as a negotiated service. This assurance does not provide any degree of certainty to APTPPL in the context of the Rules, as there is no linkage within the rules between the definition of

[6] Australian Energy Regulator 2011, NT Gas Access arrangement proposal for the Amadeus Gas Pipeline 1 August 2011 – 30 June 2016: Final Decision, July p 139

Reference Services, and the extensions and expansions policy. It is therefore unclear how the AER would take such a consideration into account. APTPPL therefore considers that the risk is not slight as the AER would suggest.

Scope for fixed principles were included in the gas access regime to provide a mechanism to give certainty to service providers that certain provisions that were important to long term decision-making could be locked in across access arrangement. It is exactly this feature of fixed principles that led the AER to reject NT Gas's proposed fixed principle because it would prevent changes to how costs for negotiated services were managed in the future. Rejecting a fixed principle because it limited scope for future changes in approach negates the intent of fixed principles in the gas access regime, and suggests that the AER would never accept a fixed principle.

Finally, APTPPL does not agree with the AER that acceptance of the proposed fixed principle would cause inflexibility in the extensions and expansions requirements. The fixed principle relates to the treatment of capital expenditure, operating expenditure and demand for services offered as Negotiated Services. In that respect it operates only retrospectively; that is to investment made during an earlier access arrangement period, and operates to protect the investment assumptions that underpinned those investment. There is nothing in the fixed principle that would stop the AER from requiring changes to the operation of future extension and expansion policies.

To make this clear, APTPPL has revised the wording of the principle as it was proposed for the AGP access arrangement to clarify that the aspects of clauses 7.1(d) and 7.2(c) that is fixed is for extensions or expansions made in reliance of this provision.

Should the AER not accept inclusion of clause 7.1(d) or 7.2(c) as a fixed principle, then these clauses will need to be varied to allow APTPPL to incorporate relevant costs in the calculation of the Reference Service if the AER later determines that services provided via a relevant extension or expansion makes up part of the reference service.

1.4.5 Queuing Policy

APTPPL proposes to move from a first-come first-served queuing policy to a public auction process for spare Existing and Developable Capacity. This is discussed in more detail in Section 10.

1.4.6 Capital redundancy

APTPPL has included a capital redundancy mechanism in the access arrangement. The capital redundancy mechanism is consistent with Rule 85, and provides for assets to be removed from the capital base where they cease to contribute in any

way to the delivery of pipeline services. The mechanism also provides for the sharing of costs associated with a decline in demand for pipeline services between APTPPL and users, consistent with Rule 85(3).

1.4.7 Capacity Transfer

As required under the Rules, APTPPL has included capacity transfer requirements in the access arrangement. These requirements have been substantially revised since the last access arrangement to take account of changes from Code to Rules, as well as the introduction of the STTM in Queensland. The requirements are very similar, however, to those approved by the AER in respect of the AGP access arrangement.

The capacity transfer requirements in the APTPPL access arrangement provide for:

- The transfer of a User's contracted capacity by subcontract to a third party without requiring APTPPL's consent; and
- Other assignments of contracted capacity may be made with the consent of APTPPL, subject to payment of APTPPL's costs associated with the transfer and compliance with APTPPL's reasonable commercial and technical conditions, the nature of which are described in the access arrangement.

1.4.8 Changing receipt and delivery point

As required under Rule 106, APTPPL's access arrangement includes provision for the change of receipt and delivery points by users. These requirements have been substantially revised since the last access arrangement to take account of changes from Code to Rules. The requirements are very similar, however, to those approved by the AER in respect of the AGP access arrangement.

The requirements for changing receipt and delivery points in the APTPPL access arrangement provide that a user may, by giving at least 45 days notice before the proposed change, request substitution of all or part of an existing receipt or delivery point MDQ for another receipt or delivery point (as relevant) provided the proposed substitution is to a receipt point or delivery point which has all the necessary facilities required to be located at the applicable Delivery Point or Receipt Point.

APTPPL may withhold its consent to all or part of a request to change receipt or delivery points on reasonable commercial or technical grounds, or make its consent subject to conditions which are on reasonable commercial or technical grounds. Examples of such reasonable commercial or technical grounds are provided in the access arrangement. It is not possible to make these grounds definitive as they will depend on the circumstances of the transfer, however APTPPL notes that they would be potentially subject to dispute resolution processes if the user does not consider that they are reasonable.

1.4.9 Reference services

Rule 101 requires a Full Access Arrangement to contain a statement of reference services:

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

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

Consistent with the previous AA, the Reference Service defined by the revised AA is a non-interruptible service for the receipt, transportation and delivery of gas through any length of the Pipeline in the direction from Wallumbilla or Peat to Brisbane.

The Reference Service is provided at the Reference Tariff.

The Reference Service includes the following:

(a) receipt of gas at the Receipt Points;

(b) transportation of gas through the Pipeline, including use of compression facilities installed on the Pipeline;

(c) delivery of gas at the Delivery Points;

(d) provision of an Overrun facility; and

(e) for installations owned and operated by APTPPL, the measurement of gas quantity and quality and of gas pressures.

APTPPL also offers Negotiated Services on the pipeline.

1.4.10 Reference tariffs

Rule 48(1)(d)(i) requires the full AA to specify the Reference Tariff for each Reference Service.

Reference Tariffs are developed according to the requirements of the Rules in Section 9. Consistent with the previous AA, Reference Tariff consists of the sum of the:

(a) Capacity Charge; and

(b) Throughput Charge;

Also consistent with the previous AA, the User may also be required to pay the following charges:

(a) Overrun Charge;

(b) Imbalance Charge;

(c) Daily Variance Charge; and

(d) Charges in respect of Receipt Stations and Delivery Stations;

As set out in the proposed revised AA.

2 Regulatory Obligations

Compliance with regulatory obligations is a substantial driver of costs for APTPPL, and underpins a significant proportion of capital and operating expenditure included in the next AA. Compliance with applicable regulatory obligations and requirements is one of the four factors listed under Rule 79(2)(c) for the justification of capital expenditure, and is embedded in the concept of prudent expenditure required for both capital and operating expenditure under the Rules.[7]

Since the last AA was approved, there have been significant changes to both the national economic regulatory framework applying to the RBP, but also the nature of the market in Queensland.

These developments, as well as changes to relevant technical and safety regulation, are discussed below, and referenced throughout APTPPL's submission and associated Asset Management Plan and business cases for individual projects.

2.1 National Regulatory Obligations

2.1.1 National Gas Law and Rules

In July 2008 the new National Gas Law (NGL) and Rules were introduced. These provisions replaced the former National Gas Code, under which the earlier access arrangement was approved.

While many aspects of the former National Gas Code are replicated in the new Gas Law and Rules, there are some significant differences in the regimes that are likely to drive costs for the RBP in the access arrangement period. Key changes in the NGL (compared to the previous Act) include:

- Establishment of new information gathering powers, allowing the AER to issue binding Regulatory Information Notices and Regulatory Information Orders on service providers. These powers differ from the previous National Gas Code as they allow the AER to specify the form and content of information to be provided to the AER;
- Extension of regulatory information powers to related providers;
- Extension of compliance monitoring and enforcement powers;
- Establishment of new arrangements for greenfield developments and scope for light regulation of covered pipelines and networks; and
- Establishment of the Short Term Trading Market and associated procedures.

[7] Rules 79(1) and 91(1)

APTPPL notes that it has incurred additional compliance costs in the preparation of this access arrangement revision proposal compared with those it would have incurred under the former National Gas Code. These additional costs are due to increased administrative and legal costs arising from the RIN issued by the AER (both in responding to consultation processes on the RIN and preparing information in accordance with the RIN), and in interpretation and analysis of new and changed requirements under the NGR.

APTPPL has also included an estimate of costs for preparing revisions to the access arrangement in 2016/17 in its forecast operating expenditure proposal.

2.1.2 National Greenhouse and Energy Reporting Act 2007

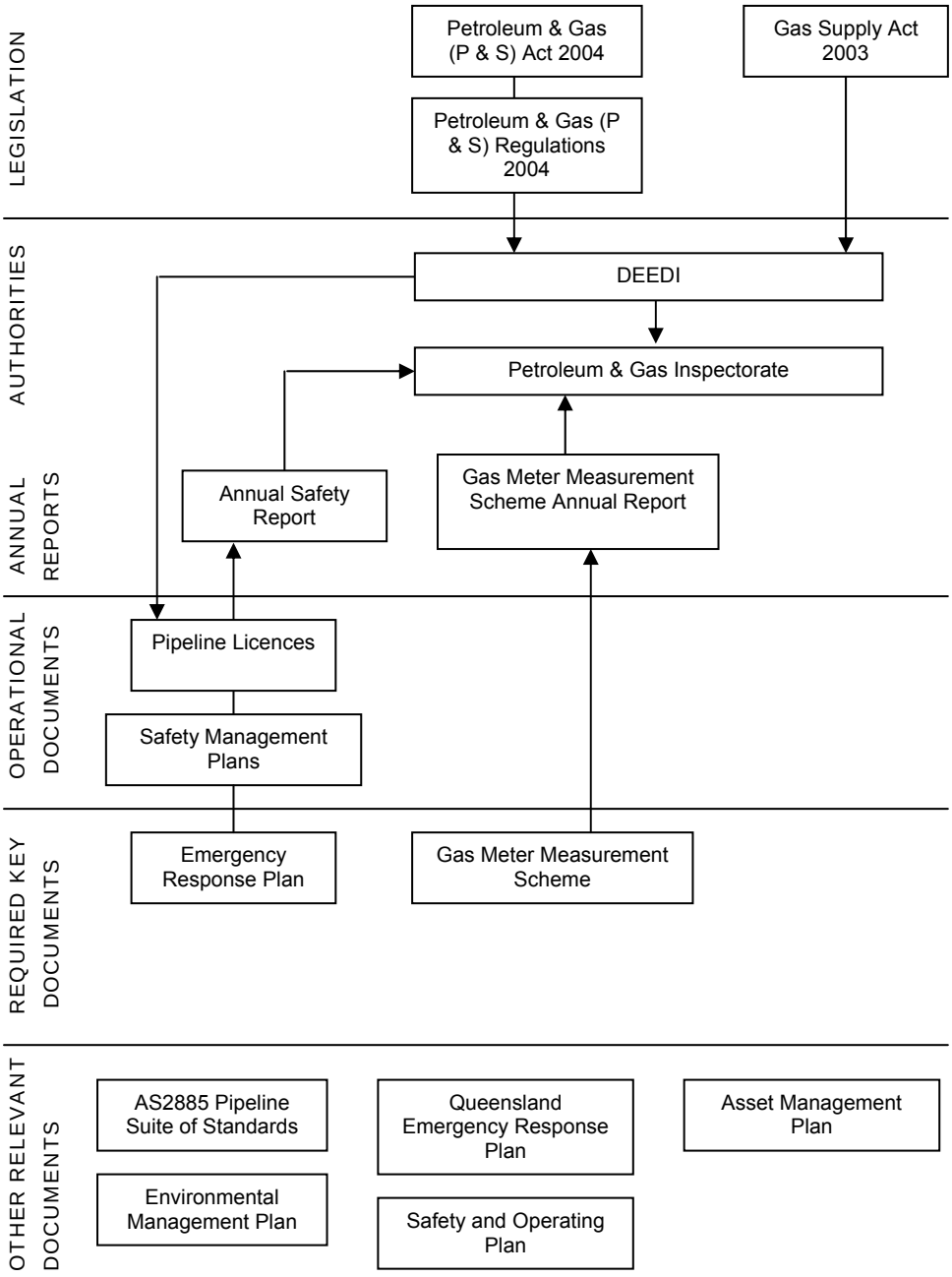
The National Greenhouse and Energy Reporting Act 2007 requires that organisations triggering thresholds as defined by the Act report energy and emissions data. Thresholds relate to emissions of CO2 equivalent, total amount of energy produced and total amount of energy consumed.

APTPPL develops monthly reports on emissions associated with the pipeline (largely related to the operation of the compressor) and provides these to APA Group, who collate emissions reports from across the business group and reports these to the federal government as required under the Act.

2.2 Queensland Regulatory Obligations

A number of state-based legislative instruments govern the operation of the RBP in Queensland. These instruments largely relate to non-economic regulation of the gas transmission business and safety and technical regulation. Figure 2.1 shows the relationship between these instruments and associated obligations, which are discussed further in the following sections.

Figure 2.1: Key Queensland regulatory obligations



2.2.1 Petroleum and Gas (Production and Safety) Act 2004

The main purpose of this Act is to regulate the petroleum activities in Queensland including the exploration, recovery and transportation of petroleum and fuel gas. For the networks sector, the Act is largely focused on environmental regulation and safety, and includes obligations for network operator in relation to:

- Gas Measurement, including a requirement for a measurement scheme;
- Safety, including details of overall safety requirements and an obligation to develop a Safety Management Plan which details the Safety Management System that must be in place for design, construction, testing, commissioning and maintaining gas assets;
- Emergency response, including an obligation to have an emergency response procedure and 24 hour access for the public to report emergencies;
- Incident reporting;
- Provisions for working with public land authorities; and
- Offences under the Act.

Certain regulations under the Act are also relevant to the RBP. The Regulations include provisions to:

- Prescribe the quality of gas;
- Specify mandatory and preferred standards to apply in relation to safety requirements; and
- Specific obligations for incident reporting.

2.2.2 Gas Supply Act 2003

The *Gas Supply Act 2003* (Qld) regulates non-economic aspects of pipeline businesses including connection of customers, licensing and consumer protection.

A pipeliner cannot transport gas in Queensland without a relevant pipeline licence. The licence imposes obligations on the distributor to:

- Take appropriate account of the environmental effects of activities carried out under the distribution authority;
- Pay amounts required to be paid under the authority or the Act;

- Comply with the Act, the Petroleum and Gas (Production and Safety) Act and all other relevant laws; and
- Comply with obligations associated with works in publically controlled places (work directions, guarding etc).

All industry participants are required to inform the Queensland Government, as soon as practicable, of any significant disruption, or event likely to result in a significant disruption, to the supply of processed natural gas. The Queensland Government can also require any industry participant to give in the approved form information in relation to, for example:

- Processed natural gas production and estimated future production, by location;
- Processed natural gas purchases, by location;
- Processed natural gas supplied and future contractual obligations to supply, by location;
- The number of customers in each stated class of customer;
- Transportation prices;
- Processed natural gas prices for a stated class of customer; and
- Estimated reserves of coal seam gas and natural gas.

2.2.3 Workplace Health and Safety Act 1995

The *Workplace Health and Safety Act 1995* (Qld) establishes a "duty of care" for employers and employees to provide a safe place of work, safe system of work, safe plant and machinery and competent staff.

2.2.4 Environmental Protection Act 1994

The *Environmental Protection Act 1994* (Qld) applies to activities impacting the air, land or water, and covers contamination, noise and waste. The Act applies to APTPPL's operations in both the construction and operation of its pipeline, including the pipeline directly, as well as associated depots, sites and other facilities.

APTPPL uses the APIA Code of Environmental Practice for Onshore Pipelines as guidance in meeting its obligations under this Act and associated Regulations.

2.2.5 Applicable Regulations, Codes and Standards

The following Regulations apply to APTPPL under relevant Acts, and provide prescriptive standards for each of the relevant Acts:

- Petroleum and Gas (Production and Safety) Regulation 2004;
- National Gas (Queensland) Regulation 2008;
- Gas Supply Regulation 2007;
- Workplace Health and Safety Regulation 2008; and
- Environmental Protection Regulation 1998.

The following are supplementary Acts and Regulations that APTPPL must work under:

- Disaster Management Act 2003;
- Clean Energy Act 2008;
- Integrated Planning Regulation 1998; and
- Native Title (Queensland) Act 1993.

2.3 Australian Standards and Codes

AS2885 "Pipelines – Gas and liquid petroleum" (Sections 1 to 5) is a mandatory standard for the design, construction, operation and maintenance of transmission pipelines in Queensland under the *Petroleum and Gas (Production and Safety) Regulation 2004* and amendments.

Other applicable standards include.

API Spec 5L	Specification for line pipe
API STD 617	Axial and Centrifugal compressors and expanders compressors for petroleum, chemical and gas industry services
APIA	Code of environmental practice
AS 1170	Structural design actions
AS 1210	Pressure vessels
AS 1518	External extruded high-density polyethylene coating system for pipes
AS 1657	Fixed platforms, walkways, stairways and ladders
AS 1692	Tanks for flammable and combustible liquids

AS 1940	Storage and handling of flammable and combustible liquids
AS 2381	Electrical equipment for explosive atmospheres - selection, installation and maintenance
AS 2430	Classification of hazardous areas
AS 2832	Cathodic protection
AS 3000	Electrical installations – Buildings, structures and premises (SAA Wiring rules)
AS 4041	Pressure piping
AS 4799	Installation of underground utility services and pipelines within railway boundaries
AS 4853	Electrical hazards on metallic pipelines
ASME B31.3	Process piping guide
	Australian rainfall and runoff – A guide to flood estimation (Institution of Engineers Australia)

3 Demand forecasting

This section provides historical User and demand information, and then applies this information and other market indicators to forecast demand into the future. Some information in this section would allow individual customers to calculate the loads of competitors. This information has been redacted from this public edition.

Some information has been redacted from the public version of this load forecast. This information, if provided publicly, would enable some shippers to determine the load and demand of other competing shippers. While this information has been provided to the AER, it has been redacted from the public version of this submission to protect the commercial information of shippers.

The ACCC's 2007 Final Decision on the RBP Access Arrangement, and the ACCC-drafted and –approved Access Arrangement make it very clear that the Existing Capacity of the pipeline as configured at 01 January 2006 is available to provide the Reference Service at the Reference Tariff. Section 7 of the 2006-12 AA clearly indicated that any capacity resulting from extensions or expansion of the pipeline will be offered as a Negotiated Service at a Negotiated Tariff. The ACCC identified "the capacity of the pipeline as currently configured (including the location of receipt points and loads) is approximately 203 TJ/day".[8]

For the purpose of developing Reference Tariffs, it is important to be able to allocate costs between the Reference and Negotiated services. This load and demand forecast therefore reports actual and estimated historical demand and throughput by service, and forecast capacity and throughput by service, to aid in this cost allocation.

3.1 Historical actual and estimated User numbers

Users of the RBP include gas producers, retailers, power generation Users and large industrial Users. Where an end user contracts for gas supply through a retailer, the retailer is the User of the RBP rather than the end user.

Table 3.1: Historical User numbers

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12F
Total users	8	9	11	11	11	11

In the absence of information regarding any new projects, the number of Users on the pipeline is forecast to remain stable:

[8] ACCC Final Decision, p7.

Table 3.2: Forecast User numbers

	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast users	10	10	10	10	9

3.2 Historical actual and estimated demand

Volumes and demand are identified by market segment: for Gas-fired Power Generation (GPG) and non-GPG loads. As discussed more fully in the load forecasting section below, this delineation is important to understanding the approach to, and reasonableness of, the demand forecast below.

Table 3.3: Historical reserved capacity

(TJ/day)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12F
Reference Service:						
GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Non GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Total	197	203	203	203	203	203
Negotiated Service:	0	0	5	16	16	16
Total	197	203	208	219	219	219

Table 3.4: Historical volumes

(TJ)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12F
Reference Service:						
GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Non GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Total	61,658	61,377	62,028	57,342	57,667	58,431
Negotiated Service:	0	0	1,489	4,345	4,316	4,402
Total	61,658	61,377	63,516	61,688	61,982	62,833

Two key inferences can be drawn from this information. First, given stable capacity reservation, is a slight deterioration of the load factor applicable to the GPG load. The second is a relatively low level of load growth in the non-GPG sector.

Adjusting for step changes associated with particular projects, this table indicates an annual average composite non-GPG compound growth rate of 1.19% pa.

3.3 Demand forecast overview

The demand forecast is important for the pipeline as this drives the need for future capital expenditure. It is also the dominant driver of revenue, with 95% of the total revenue requirement derived through capacity or demand charges. This forecast therefore focuses on the capacity forecast and then derives the throughput forecast.

To understand the nature of the gas transmission pipeline demand forecast, it is important to keep in mind the key differences between gas transmission pipelines in comparison to gas distribution networks. It is also important to note the key differences between gas transmission pipelines and electricity transmission systems.

Distribution networks (both gas and electricity) tend to have steady, organic load growth that follows population trends and, to some extent, levels of economic activity. Similarly, electricity transmission systems must meet the demands of the diverse community, including a significant domestic and commercial load.

But the gas distribution network is not generally the key driver of the gas transmission business; this is particularly the case in Brisbane, where the domestic and small commercial load accounts for only 7%[9] of the total demand on the transmission pipeline and, in the absence of a climate-driven space heating load, is growing at a relatively slow rate.

Rather, demand tends to grow on the transmission pipeline in discrete steps, where a new project has commenced operations or a new manufacturing facility has opened. Generally, it is possible to align a particular step of load growth to a particular project.

Like many gas transmission pipelines, the RBP's demand growth tends to be "lumpy" and linked to particular projects.

3.4 Forecasting methodology

APTPPL has segregated the market into its two key components for demand forecasting purposes: the GPG and non-GPG (domestic, commercial and industrial use) market.

As discussed below, the drivers for these types of demands are markedly different, as are their demands for capital investment on the pipeline.

[9] APT Allgas 2011/12 Tariff V load 2.9PJ (AAI Table 4.1); Envestra Queensland Tariff R and V load combined 2.0PJ (AAI Table 10.4).

APTPPL then conducts a reasonableness check of its resulting forecast by comparing to independent forecasts conducted by AEMO and DEEDI.

3.4.1 Gas fired power generation

APTPPL has not had any specific, firm advances on securing energy supply to any new gas-fired power generation (GPG) projects; we do not have any information to indicate that there will be a new power station on the RBP. Power station projects in particular tend to have long lead times to secure sites, fuel supply, and access to electricity transmission networks.

The *Queensland Gas Market Review*[10] also identified that it is unreasonable to assume that any new GPG projects would necessarily be served from the RBP:

> It should be noted that previous modelling of the Brisbane gas market and RBP future capacity requirements have effectively included all future projections for GPG in the South East Queensland (SEQ) region. That is, it has been assumed that gas supply to all new SEQ GPG projects will flow through the RBP. This assumption does not reflect the reality that new GPG projects are locating on the gas fields and taking primary gas supply directly from these fields. For the modelling of future gas demand for the Brisbane region, new GPG for the SEQ region has been considered as separate from the Brisbane gas market and RBP capacity requirements.

APTPPL has therefore assumed GPG demand in line with current levels.

It should be noted that any new GPG project will likely require significant augmentation of the pipeline. Consistent with this demand forecast, APTPPL has forecast no additional capex for GPG projects. If such a project materialises, APTPPL will serve that project as a negotiated service.

In 2010/11, APTPPL recorded reserved capacity of c-in-cTJ/day for GPG loads. The demand forecast reflects this level of capacity reservation for the forecast period. [Text redacted c-in-c]

3.4.2 Non GPG load

Due to the lumpy nature of demand growth on the gas transmission pipeline, demand growth tends to be forecast in discrete steps aligned to particular projects. This means that the gas transmission pipeline is largely reactive in nature,

[10] Queensland Department of Employment, Economic Development and Innovation, *2011 Gas Market Review Queensland,* p27. Attachment 3.1

dependant on the planning horizons of large project proponents. Generally, projects of this sort of size have significant lead times which include securing energy supply.

APTPPL has no specific information about particular projects on the horizon at this time. It would be reasonable, then to forecast the non-GPG load as largely flat, increasing only by the approved forecasts for the APT Allgas and Envestra Queensland distribution networks.

However, there is not a clear linkage between capacity reservation by users (retailers in particular) and the demands of the gas distribution networks. Retailers will generally reserve a margin of transmission pipeline capacity to provide for growth opportunities and customer churn. Therefore, while APTPPL has forecast organic growth in throughput in Table 3.6, it does not follow that there would be a commensurate level of increase in reserved capacity.

Consistent with the provisions of the current AA, the demand forecast below therefore reflects the Existing Capacity as being fully contracted, and the balance, up to the current total capacity of the pipeline, being served as Negotiated Services.

Table 3.5: Forecast RBP demand

(TJ/day)	2012/13	2013/14	2014/15	2015/16	2016/17
Reference Service:					
GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Non-GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Total	203	203	203	203	187
Negotiated Service:	29	29	29	29	29
Total	232	232	232	232	216

The reduction in demand observed in 2016/17 reflects the expiry of an existing shipper contract. APTPPL expects that this capacity will be subscribed via the Queuing Policy described in Section 10.

3.5 Throughput forecast

Having established the capacity forecast, APTPPL calculated the throughput forecast based on the load factors attributable to the market segments analysed. The load factor, expressed as a percentage, measures the relationship between the market segment's average daily load and its peak day load. It is calculated as (annual throughput/365)/Peak throughput. A high load factor indicates a steady load, whereas a low load factor indicates a more variable load.

From a high level perspective, it would be reasonable to expect a reduction in the average load factor for the GPG sector, reflecting the deteriorating load factor of the electricity load driven by the increased peakiness caused by the air conditioning load.[11] APTPPL has calculated the load factor inherent in the 2010 GSOO forecast (see Table 3.9 below), and notes that it is consistent with this expectation.

A review of Table 3.7 and Table 3.8 below indicates that the 2010 GSOO is forecasting a significant increase in GPG demand. As discussed above, in the absence of any information on future GPG projects on the RBP, APTPPL has forecast no changes in reserved capacity for that sector.

As discussed above, APTPPL has forecast modest growth in non-GPG throughput. APTPPL has applied the same growth rate to the current levels of throughput as it had observed in previous years as described above.

Table 3.6: Forecast RBP throughput

(TJ)	2012/13	2013/14	2014/15	2015/16	2016/17
Reference Service:					
GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Non-GPG	c-in-c	c-in-c	c-in-c	c-in-c	c-in-c
Total	60,979	61,490	61,623	62,463	57,681
Negotiated Service:	9,395	9,412	9,429	9,446	9,452
Total	70,375	70,903	71,052	71,909	67,133

The reduction in throughput observed in 2016/17 reflects the expiry of an existing shipper contract. APTPPL expects that this capacity will be subscribed via the Queuing Policy described in Section 10.

3.5.1 Throughput forecast – metro section

While the throughput in particular sections of the pipeline does not impact Reference Tariffs, it can impact the need for future capital expenditure.

As discussed in Section 4.6 for capital expenditure planning purposes, it is necessary to forecast the load in the metro section of the RBP separately from the mainline section.

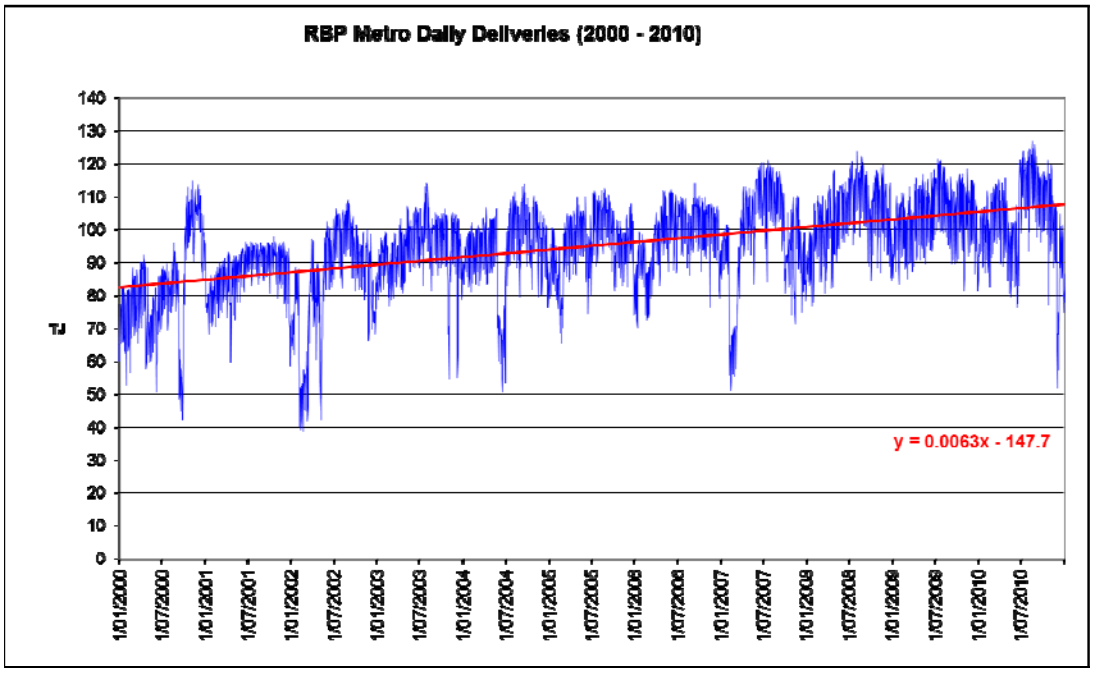
[11] It should be noted that the load factors calculated below are based on forecast winter peak demand in order to reduce this impact.

The *2011 Gas Market Review* for DEEDI indicates slow but steady forecast growth of between 1.2 and 1.8% for the loads served from the metro section (ie the non-GPG loads):[12]

> Brisbane: Projected demand of the Brisbane utility plus large industrial loads over the period 2010 to 2029 is forecast to grow at a slow but steady rate of between 1.2 per cent and 1.8 per cent; the results are very similar for all modelled scenarios.

In the 2009-2010 period, the metro section of the RBP met peak flows in the order of 125 TJ/day, as shown below. It should be noted that the goal of this analysis is to determine the longer term organic rate of growth – the step changes associated with the Lytton lateral and the RBP8 expansion do not impact this longer term organic rate of growth.

Figure 3.1 RBP Metro section deliveries



The longer term trend for metro deliveries shown in the above graph indicates that metro deliveries have been growing at a rate of approximately 2.3TJ/day per year.[13] APTPPL notes that the *2011 Gas Market Review* forecast rate of growth suggests it would be reasonable to assume demand growth in the range of 1.5 TJ/day per year.

[12] Queensland Department of Employment, Economic Development and Innovation, *2011 Gas Market Review Queensland,* p vi. Attachment 3.1.

[13] The regression analysis above is based on daily delivery data: 0.0063 x 365 = 2.2995 TJ/day per year.

Applying the 2.3TJ/day per year rate to a 2010 metro peak demand in the order of 125 TJ/day suggests peak demand growth in the order of 1.8% per year for the metro section. This rate of metro growth is largely consistent with that encapsulated in the AEMO 2010 *Gas Statement of Opportunities*[14] for non-GPG[15] load on the RBP as shown in Table 3.7 below.

It should be noted that this rate of organic metro load growth is a key input to the assessment of the need for future capacity expansion capital expenditure as discussed in Section 4.6.

3.6 Reasonableness check

To assess the reasonableness of this demand forecast, APTPPL compared the results of this process to the AEMO 2010 *Gas Statement of Opportunities*[16] for non-GPG load on the RBP. While there is some disparity between the volumes forecast by the 2010 GSOO and the actual delivered volumes shown in Table 3.4, APTPPL has focused on the rate of change in assessing the reasonableness of its forecast.

Table 3.7: 2010 GSOO Annual peak demand projections

TJ/day	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GPG	107.6	104.9	106.0	106.0	108.7	106.4	107.4	118.7	112.9	125.9
Non GPG	160.8	164.9	167.7	170.5	174.5	179.0	182.3	184.4	186.2	187.8
Total	268.5	269.8	273.6	276.5	283.2	285.4	289.7	303.1	299.1	313.7

The 2010 GSOO forecasts peak demand growth in the GPG sector of 1.76% per year, and 1.74% per year in the non-GPG sector. Together, the 2010 GSOO forecasts annual growth in the order of 1.74% per year.

[14] AEMO, *2010 Gas Statement Of Opportunities For Eastern and South Eastern Australia*, Chapter 5. Peak Demand, Winter 1 in 20 and Annual Demand, Demand Group 5, "Decentralised World" (mid) Scenario. http://www.aemo.com.au/planning/gsoo2010.html Attachment 3.2. The 2011 GSOO had not been published at the date of writing.

[15] Note that the GSOO "non-GPG" definition will include a number of delivery points upstream from the metro section.

[16] AEMO, *2010 Gas Statement Of Opportunities For Eastern and South Eastern Australia*, Chapter 5. Peak Demand, Winter 1 in 20 and Annual Demand, Demand Group 5, "Decentralised World" (mid) Scenario. http://www.aemo.com.au/planning/gsoo2010.html. Attachment 3.2. The 2011 GSOO had not been published at the date of writing.

Table 3.8: 2010 GSOO Annual throughput projections

PJ Annual	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GPG	25.6	24.3	23.1	23.2	23.2	23.4	23.2	22.8	23.0	21.3
Non GPG	52.8	54.2	55.1	55.4	56.6	58.2	59.1	59.1	60.6	60.8
Total	78.4	78.5	78.2	78.6	79.9	81.6	82.3	82.0	83.6	82.1

The 2010 GSOO forecast shows a flat (indeed slightly declining) throughput forecast to 2020 for the GPG load, and annual compound growth for the non-GPG load of 1.58% per year. Together, the 2010 GSOO forecast annual throughput growth of 0.51% per year.

The decline in forecast GPG throughput is responsible for a reduction in the GPG load factor, as discussed above. This reduction in GPG load factor is also largely consistent with the findings of the AEMO *Electricity Statement of Opportunities*,[17] which indicates that peak demand is growing at a faster rate than total energy supply (that is, peak demand is growing faster than average demand).

Table 3.9: 2010 GSOO Annual load factors[18]

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GPG	65%	63%	60%	60%	58%	60%	59%	53%	56%	46%[19]
Non GPG	90%	90%	90%	89%	89%	89%	89%	88%	89%	89%
Composite	80%	80%	78%	78%	77%	78%	78%	74%	77%	72%

As discussed above, APTPPL also had reference to the *2011 Gas Market Review* for DEEDI which indicates slow but steady forecast growth of between 1.2 and 1.8% for the non-GPG loads.[20]

3.7 Conclusion

In the absence of identified project proposals to define forecast increases in throughput and demand, APTPPL considers that, consistent with the requirements

[17] Australian Energy Market Operator, *Electricity Statement of Opportunities*, August 2011. Executive briefing Figure 3, page 15. http://www.aemo.com.au/planning/0410-0069.pdf Attachment 3.3

[18] Load factors calculated from 2010 GSOO demand and load forecasts in Table 3.7 and Table 3.8.

[19] The 2010 GSOO shows a step-up in peak demand from 2019 to 2020 but no associated increase in volumes, resulting in a reduction in load factor.

[20] Queensland Department of Employment, Economic Development and Innovation, *2011 Gas Market Review Queensland,* p vi, p27.

of Rule 74, its forecasts as shown in Table 3.5 and Table 3.6 have been arrived at on a reasonable basis, and represents the best forecast or estimate possible in the circumstances.

4 Capital expenditure

This section provides details of capital expenditure projects completed during the earlier access arrangement period and justification for the forecast capital expenditure projects.

As discussed in Section 0, capital expenditure on a gas transmission pipeline tends to be lumpy, reflecting the demands of particular large industrial projects. Increases in capital expenditure tend to closely match increases in demand.

A transmission pipeline also incurs ongoing capital expenditure of a relatively minor nature, termed “stay in business” capital. The business also undertakes necessary IT system investment.

4.1 Strategic planning

The Asset Management Plan (AMP) endeavours to optimise all interventions on the pipeline by continuously monitoring the performance of the pipeline and seeking to achieve safety and operational efficiency over the entire lifetime of the assets. The AMP provides a consolidated view of a number of technical and operational plans and how these are used to drive asset management strategies and expenditure to ensure safe, reliable and sustainable supply of gas in line with:

- Legislative obligations;
- Effective risk management;
- Financial business parameters;
- Lowest lifecycle costs; and
- Extraction of maximum value from assets;

Key issues and actions from these plans have been summarised and detailed in the AMP (Attachment 4.1). The AMP is underpinned by the Safety and Operating Plan, included as Attachment 4.1.1.

The AMP has been constructed to reflect that the RBP is now composed of four different pipelines which have different technical management requirements:

- The Peat Lateral;
- The DN250 mainline;
- The DN400 mainline; and
- The RBP metro section.

This delineation assists in understanding the capex forecast in this AA proposal. For example, APTPPL has made a key assumption that any new GPG projects will be undertaken on the mainline section of the pipeline, rather than in the Brisbane metro region. In the mainline section, any significant capex will be driven primarily by power station demand, but the mainline must also meet any growth in the metro section. Growth capex in the metro section is driven largely by the demands of the gas networks and industrial customers, while stay in business capex is influenced by the urban encroachment on the pipeline right of way.

4.2 Capital expenditure governance process

APTPPL has in place detailed capital expenditure governance processes to ensure that projects undertaken are prudent, efficient and in line with the overall strategy.

The Capital Expenditure Budget is developed as an outcome of the AMP and includes concept plans, implementation schedules for any augmentation, and high level cost estimates for all proposed capital expenditure projects.

"Stay in business" (SIB) capital expenditure works are included in the approved Capital Expenditure Budget. The capital expenditure approval is required for all other capital projects and includes relevant information like identified needs, risk assessment, options considered, cost estimation, project justification and recommendation. A package of SIB capital business cases is included as Attachment 4.2.

4.3 Pipeline capacity and utilisation

The Rules, and the Code before them, provide a clear incentive mechanism for the pipeliner not to "overbuild" the pipeline. In particular Rule 84 defers any return on and return of capital for any investment considered not to be qualifying capital expenditure at the time it was made.

As a result, where possible, pipeline capacity increments have tended to match the needs of Users for additional capacity, and consequently the utilisation of the pipeline has been historically high.

A consequence of this is that the business cases for conforming capex often include commercial information relating to specific Users. Where this is the case, these business cases are provided confidentially to the AER.

This creates a tension between the capital expenditure criteria and the reality of transmission pipeline investment. Due to the size of the increments of capacity that can be efficiently added, there will be occasions in which the pipeline carries some excess capacity.

4.4 Capital expenditure during the earlier access arrangement period

4.4.1 Comparison of ACCC final approval and outturn capital expenditure

Historical capital expenditure was incurred across two drivers: Stay In Business and growth related, as show below:

Table 4.1: Forecast vs outturn capital expenditure by driver

($m nominal)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12F	Total
ACCC Forecast ($2006)[21]	4.14	2.09	1.62	1.98	1.23	2.59[22]	13.75
ACCC Forecast ($nominal)	4.24	2.23	1.77	2.23	1.43	3.20	15.11
Actual - SIB	2.57	2.58	2.72	4.13	2.58	3.75	18.34
PMA Contract		30.07					30.07
Variance - SIB	(1.67)	30.42	0.95	1.90	1.15	0.55	33.30
ACCC Forecast Growth	0	0	0	0	0	0	0
Actual - Growth	0	0.15	0.34	6.86	7.47	45.95	60.77
Variance - Growth	0	0.15	0.34	6.86	7.47	45.95	60.77
Total Variance	(1.67)	30.57	1.29	8.76	8.62	46.50	94.07

The major sources of variation are discussed below.

PMA contract buyout

Stay in Business capital, 2007/8, $30.1m

A feature of the previous AA was that APTPPL contracted the planning, design, capex project management, and operation and maintenance of the pipeline to a third party, Agility Asset Management (Agility). The costs associated with this form of

[21] APT Petroleum Pipelines Limited Access Arrangement Information Approved by the ACCC, 28 March 2007, Table 3.

[22] Sourced from ACCC 2006 AA model. The previous AAI did not include this forecast.

service provision, including a margin paid to Agility, were approved and included in the operating expenditure forecast approved by the ACCC.

In June 2007, APA Group acquired the Agility asset management business from Alinta. The acquisition effectively internalised the construction, management and services functions by acquiring the various asset management contracts as well as some items of property, plant and equipment. In addition, APA Group took over all 270 employees working in the business.

As a direct result of this contract buyout, APTPPL will no longer incur the margins paid to the contracted operator, resulting in cost savings and a commensurate reduction in the future Reference Tariff relative to the counterfactual. APTPPL has therefore capitalised the cost of the contract buyout as the investment to achieve these operating cost savings.

This is discussed in more detail in Attachment 4.3.

Lytton Lateral

Growth capital, 2009/10 and 2011/12, $9.05m

In the 2009/10 and 2010/11 fiscal years, APTPPL extended the RBP by constructing 6.2 km of 200mm steel pipeline with associated infrastructure, at final cost of $8.66m to serve additional capacity to a major industrial user at Lytton. While the cost of this pipeline is underwritten by commercial arrangements with the shipper, this lateral also opens access to new industrial sites in the Lytton region.

APTPPL has provided a detailed business case, including project costings and economics, to the AER. As this business case includes commercial information relating to a particular User, it has been provided confidentially.

RBP8

Growth capital, 2010/11 and 11/12, $50.6m forecast

On 28 April 2011, APA Group announced that it was undertaking an expansion of the RBP.[23] That announcement stated:

> This expansion will involve the installation of an additional compressor at the Dalby Compressor Station, duplication of a 6 km section of the Roma Brisbane Pipeline and works which will allow the pipeline operating pressure to be increased.

[23] APA Group ASX release, 28 April 2011 *APA expanding capacity of the Roma Brisbane Pipeline.* Attachment 4.5

The additional capacity has been substantially contracted under long term transportation agreements with an energy retailer and a major industrial gas user.

This project phase includes a package of works required to meet the contracted capacity requirements:

- Construction of approximately 6 kilometres of Class 600 DN300 pipeline between Preston Road, Carina and Paringa Road, Murarrie with a Maximum Allowable Operating Pressure (MAOP) of 10.2 Mpa.[24]
- Construction of an additional C50 Compressor at Dalby;
- RBP DN400 Maximum Operating Pressure (MOP) upgrade; and
- Ellen Grove Gate Station Pig Receiving Facility Upgrade.

The proposed investment has been underwritten by firm gas transportation agreements with existing shippers.

This project incorporates the first phase of the Metropolitan Looping Project (discussed in more detail below).

APTPPL has provided detailed business case documentation to the AER.

Consistent with the operation of section 7.2(b) of the current AA, access to services provided using this capacity are provided as a Negotiated Service at a negotiated tariff. The costs associated with this expansion are therefore excised from the total revenue requirement applicable to the determination of Reference Tariffs as discussed in Section 9.

Non System capital expenditure

SIB capex, $0.139m (2008/9); $0.28m (2009/10); $0.915m (2010/11); $0.958 (2011/12).

Since the last access arrangement, APA Group has been required to undertake significant expenditure in IT systems, both to meet the ongoing needs of the business, and to comply with imposed market mechanisms. These systems include:

- Gas Management System

  The GMS provides a web-based B2B gas management system to manage system configuration and user nominations (module one) and gas measurement

[24] It should be noted that this pipeline will not be able to operate at this pressure until the upstream phases of the metro loop are completed.

and verification, and gas allocation facilities (module 2). The GMS also manages Short Term Trading Market (STTM) functions in NSW (module 2.5).

The GMS was completed within the previous access arrangement period at a cost of $0.5 million, with an allocation to the RBP of $0.04 million.

- Portfolio and Project Operating Model

  The PPOM project seeks to establish a single portfolio and project management operating model across APA Group. This will be achieved by having consistent and aligned methods (process) across the organisation, supported by a tool (technology) that will remove inefficiencies in project delivery and portfolio reporting. The foundations set by implementing the process and technology pieces will then help develop APA Group project delivery competencies (capability) based on industry best practice in project/portfolio management. The PPOM project is highly integrated with the Financial Transportation Project to support a common set of financial project management tools within APA Group.

  The PPOM project expenditure in the previous access arrangement period is expected to be $1.4 million, with an allocation to the RBP of $0.09 million.

- Financial Transformation System

  APA Group businesses have, over the years, utilised multiple finance systems and charts of accounts, reflecting numerous legacy systems. Until recently, APA Group had three different finance systems creating considerable complexity in managing financial reporting, analysis and controls. APA Group has undertaken a project to rationalise the previous suite of finance systems to deliver ongoing savings to the APA Group businesses.

  Expenditure on the Financial Transformation Project in the previous access arrangement period is expected to be $9.0 million, with an allocation to the RBP of $0.58 million.

- Project Colin

  Project Colin comprises a number of components which seek to transform APA Group's management of its gas assets. The project includes development of a new web-based customer interface to provide metering, billing and contractual information for users, a single nominations tool for transport of gas across multiple assets, customer invoicing capabilities and customer access to real time pipeline capacity information to support nominations. Key components of the new system are:

  - Energy Components
  - Enterprise Historian

- BizTalk

Project Colin also provides a stable and expandable platform for APA Group to meet its STTM requirements. The system is highly integrated with the Financial Transformation Project.

Expenditure on Project Colin in the previous access arrangement period is expected to be $12.5 million, with an allocation to the RBP of $0.81 million.

- Enterprise Historian

The SCADA Historian project involves the development and implementation of a SCADA Enterprise Historian within APA Group. A SCADA Historian provides a secure warehouse for validated data from various SCADA systems, and provides facilities to view, manage and audit data from disparate SCADA systems in a consistent and controlled environment.

An Enterprise Historian is a key input to Project Colin, which requires a consistent data layer as an input into the Energy Components System.

Expenditure on the Enterprise Historian in the previous access arrangement period is expected to be $3.2 million, with an allocation to the RBP of $0.2 million.

More detail on these projects and project drivers is set out in confidential Attachment 4.7.

APA Group has also undertaken a number of smaller corporate IT projects of which a proportion of capital costs have been allocated to APTPPL. These projects include:

- Enterprise Risk Management;
- Finance project reporting;
- Integrity Data Management;
- National Training Project;
- Human Resources Information System; and
- Transmission Transformation.

In total, the capitalised amounts associated with these projects amount to $0.6 million. These projects have been undertaken to address a variety of needs, mostly associated with gaining national consistency in systems and/or processes, thereby reducing risks to the business. All projects contribute to the provision of pipeline

services my providing essential back office risk management, human resources or financial management functionality.

As the above projects are undertaken nationally, only a portion of the cost of these projects has been capitalised in the RBP. The allocation methodology is consistent with that for corporate costs more generally, whereby costs are allocated to specific assets first by driver, with the remainder allocated in proportion to APA Group revenue.

In all cases the amount to capitalised for the RBP is less than the cost that an equivalent system could be built on a stand-alone basis. The total cost of these systems capitalised to the RBP is $2.3M.

Two projects (GMS and Project Colin) are potentially subject to an alternative cost recovery mechanism through the STTM rules.[25] APTPPL intends to reflect the outcome of the current process assessment for this cost recovery amount in response in its revised proposal in response to the AER Draft Decision.

Regulatory treatment of costs and benefits from projects

APA Group has initiated a number of corporate IT projects aimed at developing nationally consistent and streamlined business processes within the Group. In most cases the driver for investment is stay-in-business: the investment is essential to replace inappropriate, obsolete or unsupported systems; and/or the risk (regulatory and integrity) to APA Group's ability to maintain pipeline services under the current approach is unacceptable for the business.

At the same time, however, some efficiency benefits are expected to be achieved over the longer term from these benefits. In most cases these are not the main driver for investment. Potential efficiency benefits have been identified at a high level only.

APTPPL has not included these potential efficiency gains in its forecasts for operating expenditure. A key reason for this is that potential gains are not able to be accurately forecast at this stage, and may not eventuate in the forecast period.

APTPPL also does not consider that including a forecast of expected efficiencies in forecast operating expenditure would be consistent with the incentive properties of the gas access regime. One of the regime's key features is an ex ante setting of revenue based on efficient costs, with the service provider able to retain for a period any efficiency gains or savings made during the period. This is intended to provide the service provider with an incentive to pursue efficiency gains as these gains are not immediately returned to users. The application of an up-front forecast of efficiency gains associated with specific investments before they are earned is not consistent with this incentive-based approach. This argument has previously been

[25] Rule 424

made by GasNet in respect of efficiency gains for the Victorian Principal Transmission System[26], and accepted by the ACCC in it is final decision.[27]

Once potential efficiency gains are realised, these gains will be passed on to users through the normal access arrangement revision processes which base forecast operating expenditure on actual costs. This approach means that service providers have an incentive to seek out difficult to realise efficiency benefits by having the opportunity to keep the benefits of those efficiency gains for a period, whilst users will also benefit from those gains through lower tariffs in the longer term.

4.4.2 Cost efficiency of historical capital expenditure

To ensure capital expenditure is delivered efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering pipeline services, APTPPL has conducted tender processes to engage suitably qualified contractors to undertake material works.[28]

In summary, these processes involved the following steps:

- Developing the contracting strategy;
- Develop contracting scope;
- Public advertisement for Expression of Interest;
- A defined and rigorous tender process;
- Tender assessment;
- APT Board approval process;
- Contract implementation; and
- Ongoing Contract Strategy Review.

For historical capex projects, a summary of the tender process applied for material each project is included in the relevant business case documentation.

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[26] APA Group 2007, *Response to the Commission's draft decision on proposed access arrangement for the Principal Transmission System*, 20 December, pp 38-41

[27] Australian Competition and Consumer Commission 2008, *Final Approval Revised access arrangement by GasNet Australia (operations) Pty Ltd and GasNet (NSW) Pty Ltd for the Principal Transmission System*, 25 June, p 9

[28] Due to the lumpy nature of transmission pipeline capex, each project over a materiality limit is tendered individually. This contrasts to distribution networks, which will generally conduct a single tender process for ongoing capital works.

For material future capex projects, APTPPL will follow the APA Group tendering procedures provided in Attachment 4.8.

It should be noted that these historical and forecast projects do not include any element of "outsourced expenditure" as envisioned in current Australian regulatory practice.

4.5 Forecast capital expenditure

4.5.1 Growth

As discussed above, growth capex projects generally align to significant increases in shipper demand. As outlined in Section 0, APTPPL does not have any requests for significant increases in capacity at this time.

As the demand forecast indicates stable demand over the forecast period, APTPPL does not forecast any growth related capital expenditure at this time.

4.5.2 Stay in business

A pipeline system undertakes routine capital activities targeted at maintaining the pipeline in good working order in the long term. These projects, such as pigging, are of a relatively minor nature, and are outlined in the Asset Management Plan included as Attachment 4.1.

Stay in business capital expenditure is forecast as follows:

Table 4.2: Stay in Business capex

($m) 2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	Total
SIB Capex	3.99	4.46	3.33	3.54	2.98	18.31

As many SIB capex projects tend to be of a recurring nature, some are reflected in both the historical and forecast SIB capex. Accordingly APTPPL has filed a single attachment of historical and forecast SIB capital projects in Attachment 4.2.

4.5.3 Application of escalators to forecast capital expenditure

APTPPL has not applied any labour or materials escalators to forecast capital expenditure as the effect of applying escalators would not be significant given the size of the capital budget.

APTPPL notes that there is currently before Federal Parliament bills to implement a carbon price on greenhouse gas emissions. Should this legislation pass the

Parliament, APTPPL will assess the likely impacts of this new legislation on input prices of both a capital and operating nature. As a result of this assessment, APTPPL may determine to apply a carbon price escalator to those costs.

4.5.4 Forecast capex by driver

In summary the forecast capex is comprised of only Stay In Business capex, as follows:

Table 4.3: Forecast capex by driver

($m) 2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Expansion	0	0	0	0	0	0
Replacement	0	0	0	0	0	0
Stay In Business	3.99	4.46	3.33	3.54	2.98	18.31
Total	3.99	4.46	3.33	3.54	2.98	18.31

4.6 Future capital expenditure

While not included in the capital expenditure forecast in this AA revision proposal, APTPPL believes it is important to signal to the market any significant capital expenditure that may be required late in the upcoming AA period or early in the following period.

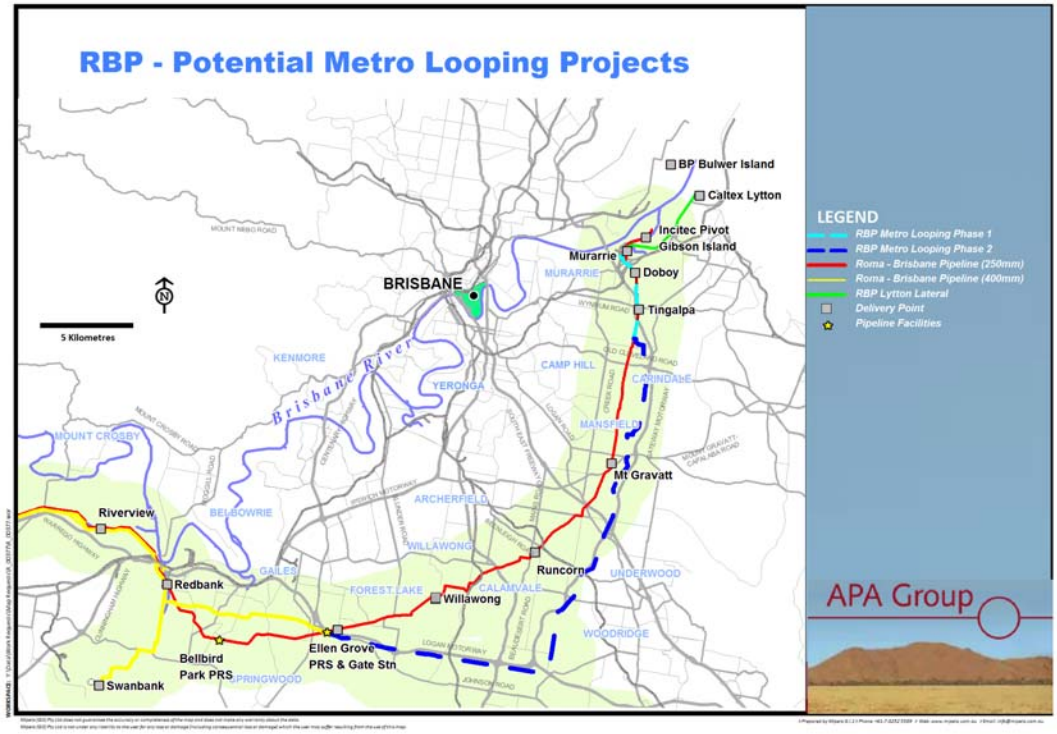
As discussed above, the RBP is considered as four distinct pipelines for asset management purposes: the Peat lateral, two mainline pipelines, and the metro section in Brisbane.

The capacity of the RBP is expected to be constrained at some point in the future by the capacity of the metro section.

It is likely that action will be required to ensure that the RBP can meet the demands of customers into the future. However, the timing of this action is not clear, as it may be influenced by any capacity trading activity undertaken following the commencement of the Short Term Trading Market.

As shown in the map below, the most likely solution to develop capacity in the metro section will be the completion of looping of the existing metropolitan pipeline at an estimated cost of approximately $50 million.

Figure 4.1 Potential RBP metro loop



As APTPPL does not propose to include the capital expenditure in the 2012-17 AA period forecast, APTPPL has not filed business case or detailed cost information with this AA proposal.

5 Capital base

5.1 Reconciliation of opening capital base

The opening capital base for the previous AA period is generally derived using a forecast for capex in the last year of the AA period prior to that. As a result, it is generally necessary to "true up" the forecast capex for actual incurred capex.

However, in this case the opening capital base for the 12 April 2007 to 11 April 2012 AA period is indeed the Initial Capital Base. There is therefore no need to adjust it for actual capital expenditure in the prior AA period.

None of the assets which comprise the opening capital base are or have been subject to compensation claims through legal or court action, insurance or other processes.

5.2 Depreciation

The capital base has been rolled forward using the depreciation allowed by the ACCC in its 28 March 2007 Final Decision, adjusted for outturn inflation, as follows:

Table 5.1: 2006-12 Outturn depreciation

$000 nominal	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
ACCC forecast depreciation ($2006)	5.85	6.12	6.19	6.32	6.62	6.70[29]
Nominal Actual Straight-line Depreciation	-6.02	-6.46	-6.81	-7.12	-7.68	-8.15
Nominal Actual Inflation on Opening RAB	7.22	12.73	8.41	9.98	12.00	9.37
Outturn depreciation	1.20	6.27	1.60	2.87	4.32	1.22

5.2.1 Asset lives

APTPPL has not changed the standard asset lives from those approved by the ACCC at the last review. The asset lives approved by the ACCC were specific to each capacity expansion project, resulting in a variety of remaining asset lives attributable to pipeline assets:

[29] Sourced from ACCC 2006 regulatory model.

Table 5 2: Asset Economic Lives (years)

Asset Class	Standard life	Remaining life	Tax Statutory Life	Remaining tax life
Original Pipeline	60.00	17.00	20.00	n/a
Looping 1	80.00	56.00	20.00	n/a
Looping 2	80.00	58.00	20.00	n/a
Looping 3	80.00	66.00	20.00	6.00
Looping 4	80.00	69.00	20.00	9.00
Looping 5	80.00	71.00	20.00	11.01
Looping 6	80.00	71.00	20.00	11.14
Lateral	80.00	69.00	20.00	9.09
Dalby Compressor	35.00	5.00	20.00	9.50
Kogan Compressor	35.00	5.00	20.00	5.08
Oakey Compressor	35.00	6.00	20.00	6.13
Condamine Compressor	35.00	7.00	20.00	5.06
Yuleba Compressor	35.00	9.00	20.00	5.96
Gatton Compressor	35.00	10.00	20.00	3.73
Easements	1,000.00	957.00	n/a	n/a
Communications	15.00	4.00	20.00	n/a
Other	5.00	n/a	20.00	6.83
Capitalised AA costs	5.00	4.92	5.00	4.93
Pipelines / Laterals	80.00	78.12	20.00	18.31
Group IT	5.00	4.34	5.00	4.35
SIB Capex	5.00	3.47	5.00	3.52
PMA	12.00	8.00	5.00	1.00
Regulator and meter stations	40.00	35.69	20.00	15.74
Lytton lateral	80.00	79.00	20.00	19.00
RBP Expansion - Stage 8	35.00	35.00	20.00	20.00

5.3 Capital Base roll forward

5.3.1 Historical

The Capital Base has been rolled forward in accordance with the provisions of Rule 77(2). The opening capital base for the access arrangement period[30] is shown Table 5.3 below.

Table 5.3: Capital base roll forward

$m nominal	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Opening capital base	296.35	300.22	340.88	345.66	359.98	374.80
Plus capex	2.67	34.39	3.18	11.45	10.50	51.68
Plus speculative capex						
Plus reused redundant assets						
Less depreciation	-6.02	-6.46	-6.81	-7.12	-7.68	-8.15
Plus indexation	7.22	12.73	8.41	9.98	12.00	9.37
Less redundant assets						
Less disposals						
Closing capital base	300.22	340.88	345.66	359.98	374.80	427.70

5.3.2 Forecast

The projected Capital Base has been rolled forward in accordance with the provisions of Rule 78:

[30] As required by Rule 72(1)(b)

Table 5.4: Forecast capital base roll forward

$m nominal	2012/13	2013/14	2014/15	2015/16	2016/17
Opening capital base	427.70	426.47	424.52	419.92	415.54
Plus capex	4.24	4.86	3.72	4.06	3.51
Plus speculative capex					
Plus reused redundant assets					
Less depreciation	(16.67)	(17.98)	(19.44)	(19.44)	(18.80)
Plus indexation	11.21	11.17	11.12	11.00	10.89
Less redundant assets					
Less disposals					
Closing capital base	426.47	424.52	419.92	415.54	411.14

6 Weighted Average Cost of Capital

6.1 Introduction

This chapter explains the parameters and methodologies proposed to be applied to estimate the weighted average cost of capital (WACC) for RBP in the forthcoming access arrangement period.

6.1.1 Legal requirements

In determining the parameters that constitute the WACC for RBP, regard must be given to the relevant provisions of the National Gas Law (NGL) and National Gas Rules (NGR). Any decision on the WACC should be consistent with the National gas objective as set out in the NGL:[31]

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

In addition, there are two relevant provisions in the NGR. Rule 87 provides:

> (1) The rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.
>
> (2) In determining a rate of return on capital:
>
> (a) It will be assumed that the service provider:
>
> (i) Meets benchmark levels of efficiency; and
>
> (ii) Uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice; and
>
> (b) A well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be used; and a well accepted financial model, such as the Capital Asset Pricing Model, is to be used.

Rule 74(2) requires that a forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

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[31] *Section 23 of the National Gas Law.*

6.1.2 Approach

APTPPL proposes to continue setting the rate of return on the RBP by reference to a nominal 'vanilla' post-tax WACC. The nominal 'vanilla' post-tax WACC is defined by the following formula:

$$WACC = r_e \frac{E}{D+E} + r_d \frac{D}{D+E}$$

where

r_e is the nominal return on equity, determined by a domestic Sharpe-Lintner capital asset model (CAPM), i.e.:

$$r_e = r_f + \beta_e \times \left(r_m - r_f\right)$$

where

r_f is the domestic risk free rate;

β_e is the equity beta of a hypothetical gas pipeline service provider; and

$(r_m - r_f)$ is the domestic market risk premium;

r_d is the nominal cost of debt, as observed from observed domestic corporate bond performance, i.e.:

$$r_d = r_f + DM$$

where

DM is the nominal debt margin, i.e., the difference between the risk free rate and the yield on appropriated rated corporate debt.

$\frac{D}{D+E}$ is the debt to value ratio of a benchmark efficient business; and

$\frac{E}{D+E}$ is the equity to value ratio of a benchmark efficient business.

The following sections outline the values proposed by APTPPL for each of the above WACC parameters.

6.2 Risk-free rate

The risk free rate is a component of the return on both equity and debt. In line with standard AER practice, APTPPL proposes to calculate the risk free rate using the following steps:

- Referring to the indicative mid rates for Commonwealth Government Securities (CGS) published by the Reserve Bank of Australia;
- Identifying the two CGSs whose expiry dates straddle the date which is 10 years from the end of the sample period;
- Calculating an indicative ten year CGS yield for this date by interpolating on a straight-line basis the yields associated with these two CGSs;
- Annualising the derived 10 year CGS yield;[32] and
- Calculating the arithmetic average of this annualised yield over the 20 trading days of the sampling period.

APTPPL will propose a sampling period through correspondence with the AER.

For the purpose of calculating an indicative WACC estimate, the risk free rate has been estimated using a sampling period of the twenty business days ending 30 September 2011. The resulting average was 4.25%.

6.3 Gearing

A gearing ratio of 60% debt to value is the current assumed gearing ratio of RBP. A 60% gearing ratio is also in line with the AER's 2009 analysis of the average gearing levels of regulated gas and electricity businesses.[33] APTPPL proposes to continue to assume a 60% gearing ratio in the forthcoming access arrangement period.

6.4 Debt margin

The estimation of the debt risk premium (DRP) has been a source of contention in recent gas and electricity regulatory proceedings. With the cessation of the publication of CBASpectrum's fair value estimates in 2010, Bloomberg is the only recognised provider of fair value estimates remaining. However, rather than relying solely upon Bloomberg's (extrapolated) estimate the AER has elected to calculate

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[32] Since the reported yields are calculated as the sum of the semi annual payments. See the Reserve Bank of Australia, *Terms and Conditions of Issue – Treasury Bonds*, 18 February 2002, pages 2 and 3.

[33] AER, *Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, Final decision*, May 2009, p. 124.

the DRP based on a weighted average between this fair value estimate and the yield on an APA Group bond maturing in 2020. In its most recent decisions (Amadeus, APT Allgas) this has been a simple (equal-weighted) average. [34]

APTPPL commissioned the Consulting Economics Group (CEG) to advise on the appropriate DRP. The CEG report (included as Attachment 6.1) examines the implications of reliance on Bloomberg's (extrapolated) fair value estimate as against a simple average of this with the APA Group bond yield in arriving at an estimate of the DRP. CEG concludes that sole reliance upon Bloomberg's (extrapolated) 10-year BBB fair value estimate is the more reasonable of these two approaches upon both principled and empirical grounds.[35]

Specifically, CEG concludes that reliance upon an independent expert opinion such as that provided by Bloomberg is likely to be superior to reliance upon a single bond, such as APA Group. It notes that attempting to 'second guess' Bloomberg's fair value estimate without a clear understanding of the inputs and processes that go into that estimate is a fraught exercise.[36] Furthermore, material reliance upon a single data point is likely to be inaccurate and, because APTPPL is a subsidiary of the APA Group, likely to lead to significantly incentive problems.[37] On this basis, CEG cautions against specific reliance upon the APA Group bond and concludes that the appropriate use of bond yield data generally is as a cross-check to ensure that an independent industry estimate (such as Bloomberg's) is reasonable.[38]

The results of this cross-check indicate that there is no basis for considering that Bloomberg's (extrapolated) BBB fair value curve does not provide a reasonable estimate of the benchmark yield. Analysis of the curve against BBB+ bond data and then a wider set of BBB and A- bond data indicates that Bloomberg's (extrapolated) BBB fair value curve remains a good fit to the observed bond yield data.[39]

Extrapolation of the Bloomberg BBB fair value curve is required because Bloomberg has not reported a 10-year BBB fair value estimate since 2007, and since 22 June 2010 has ceased to provide any 10-year corporate fair value estimates. The most recent approach used by the AER to extrapolate forward the Bloomberg BBB fair value curve from 7 to 10 years is based on the shape of the Bloomberg AAA fair value curve for the 20 days to 22 June 2010 when it most recently reported 10-year estimates.[40]

CEG has reviewed this extrapolation approach against three alternative methodologies: (i) extrapolation based on the shape of the CGS yield curve; (ii)

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34 See for example, Amadeus, p. 182.

35 CEG report, sections 2 and 3.

36 CEG report, pp. 15-16.

37 CEG report, pp. 19-22.

38 CEG report, pp. 15-16.

39 CEG report, section 2.

40 AER, NT Gas: Access arrangement proposal for Amadeus Gas Pipeline, July 2011, p. 181.

based on linear extrapolation; and (iii) based on average increases in yields on bonds issued by similar issues over the 7 to 10 year interval. Ultimately CEG concludes that the existing methodology remains a reasonable fit to the contemporaneous data and is consistent with the small amount of data available on increases in bond yields over that interval. Consequently CEG recommends retention of extrapolation of the Bloomberg BBB fair value curve based upon the most recent Bloomberg AAA fair value information.[41]

The DRP calculated by CEG on this basis is 4.31%. This is calculated as:[42]

	the average annualised Bloomberg 7-year BBB fair value yield estimate over the 20 days to 30 September 2011	7.85%
plus	the average increase in annualised Bloomberg fair value CGS yields between 7 and 10 years over the 20 days to September 2011	0.23%
plus	the average increase in annualised Bloomberg AAA fair value yields between 7 and 10 years over the 20 days to 22 June 2010	0.60%
less	the average increase in annualised Bloomberg fair value CGS yields between 7 and 10 years over the 20 days to 22 June 2010	0.13%
less	the average annualised CGS 10-year yield over the 20 days to 30 September 2011 as calculated by CEG using RBA reported yields	4.25%
On this basis, APTPPL proposes a DRP of		4.31%

6.5 Market risk premium

In recent final decisions,[43] the AER has set out its view that:

- The appropriate estimate of MRP was 6.5% in mid-2009, commensurate with conditions in financial markets at that time; but
- Conditions in financial markets have since improved so that the long-run average estimate of 6.0% for the MRP is now appropriate.

41 CEG report, section 4 and particularly 4.2.

42 Noting slight variance for rounding.

43 AER Final Decision: *NT Gas: Access arrangement proposal for Amadeus Gas Pipeline*, July 2011; AER Final Decision: *Envestra Ltd: Access arrangement proposal for the Qld gas network*, June 2011; AER Final Decision: *APT Allgas Ltd: Access arrangement proposal for the Qld gas network*, June 2011; and AER Final Decision: *Envestra Ltd: Access arrangement proposal for the SA gas network*, June 2011.

In particular, the AER has concluded that its "approach of increasing the MRP to 6.5% at the time of the WACC review is no longer appropriate"[44] and that current conditions in financial markets no longer warrant any risk premium above what would be appropriate on average over the long term.

APTPPL commissioned SFG Consulting to consider the estimate of MRP that is commensurate with current conditions in the market for funds and the risks involved in providing reference services under sub-Rule 87(1) of the National Gas Rules. SFG's report (which is included as Attachment 6.2). SFG concludes that the AER has been premature in its conclusion that the events of the global financial crisis have ceased to have any effect on risk premiums in financial markets. Rather, the SFG report shows that indicators of conditions in financial markets all establish that risk premiums remain at elevated levels. Option implied volatilities, dividend yields and yield spreads in debt markets all remain well above long-run averages.

The AER's conclusion that risk premiums have returned to average levels is based largely on limited survey information and macroeconomic commentary about possible future conditions in financial markets. SFG contends that more direct evidence about the current conditions in the market for funds can be obtained from current prices in the market for funds. In this regard, there is clear evidence that a range of variables, that have been shown in the relevant literature to be associated with market risk premiums, are currently significantly above their long-run averages.

In particular, risk premiums in debt markets are demonstrably above their long-run average level. In its recent final decisions, the AER rejects the consideration of the elevated risk premiums in debt markets on two bases. First, the AER suggests that the evidence on debt premiums is unreliable so that it cannot be concluded that risk premiums in debt markets are at elevated levels;

> '[..] there is a significant paucity of data on long-term bonds with credit ratings close to BBB. This is likely to reduce the accuracy of yield forecasts for long-term BBB rated corporate bonds.'[45]

However every indicator of yield spreads in debt markets currently shows spreads remaining at elevated levels. This includes spread estimates published by the RBA and cited by the AER in its recent final decisions.[46] Moreover, the AER's own estimate of the BBB+ debt premium in all four of its recent final decisions is several times greater than pre-GFC levels. Any contention that risk premiums in debt markets are not currently at elevated levels is simply unarguable.

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[44] Amadeus Final Decision, p. 72; Allgas Qld Final Decision, p. 34; Envestra Qld Final Decision, p. 46; SA Final Decision, p. 51.

[45] Amadeus Final Decision, p. 162; Allgas Qld Final Decision, p. 138; Envestra Qld Final Decision, p. 188; SA Final Decision, p. 201.

[46] Amadeus Final Decision, p. 167; Allgas Qld Final Decision, p. 142; Envestra Qld Final Decision, p. 194; SA Final Decision, p. 185.

The AER has also argued that the evidence about risk premiums in debt markets is irrelevant because debt and equity markets are (or can be) completely disjointed.

> 'It is also not unreasonable for conditions in debt and equity markets to differ from each other over time.'[47]

The AER provides no evidence in support of this assertion. APTPPL submits that it is impossible that investors would currently require substantially higher risk premiums when investing in a firm's bonds, but no more than the long-run average premium when investing in the same firm's shares.

Having concluded that risk premiums in financial markets remain above their long-run average level, it is necessary to determine an appropriate estimate of the MRP that is commensurate with prevailing conditions in the market for funds. In this regard, the accompanying SFG report notes that:

- The AER's previous estimate of 6.5% should not be treated as an upper bound on MRP estimates, or as an appropriate estimate of the MRP at the peak of the financial crisis, because it was not based on any analysis; and

- The AER indicates that, in determining its present estimate of 6.0%, it has placed some reliance on geometric averages of historical data. It is well-known and well-established that it is wrong to place any reliance on geometric averages, as evidenced by a Harvard Business School case-study on the issue.[48] Correcting this error would lead to higher estimates of MRP.

The SFG report sets out a procedure for determining an appropriate estimate of MRP, based on information from a number of conditioning variables that have been shown in the literature to be associated with market risk premiums. Based on statistical reasoning, the SFG procedure considers MRP estimates within the range of 4-8%, around an average estimate of 6.0%. SFG demonstrate that the conditioning variables (option implied volatilities, dividend yields and yield spreads in debt markets) are all substantially above their long-run means, indicating that the present MRP is also well above its long-run mean. Specifically, given the amount by which the conditioning variables are above their mean, SFG conclude that an MRP estimate of 7.0% would be appropriate.

APTPPL has therefore adopted an MRP estimate of 7.0% as being commensurate with the prevailing conditions in the market for funds.

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47 Amadeus Final Decision, p. 163; Allgas Qld Final Decision, p. 139; Envestra Qld Final Decision, p. 189; SA Final Decision, p. 201.

48 Discussion of the incorrect use of geometric averages and the Harvard Business School case relating to the Marriott Corporation is contained in the accompanying SFG report.

6.6 Beta

The AER's current equity beta estimate (based on 60% gearing) for gas transmission and distribution businesses is 0.8. This estimate emanates from the AER's 2009 Review of WACC Parameter Estimates.

APTPPL engaged SFG Consulting to consider the estimate of equity beta that is commensurate with current conditions in the market for funds and the risks involved in providing reference services under sub-Rule 87(1) of the National Gas Rules.

The SFG report is included as Attachment 6.3. The report demonstrates that the regulatory estimate of 0.8 is statistically unreliable. The reasons for this conclusion include:

- The data set on which the 0.8 estimate is based is so small and incomplete that no econometric technique applied to it (no matter how carefully applied) can produce estimates that are precise and reliable;
- The individual estimates on which the AER's estimate is based are, in many cases, implausible;
- The individual estimates on which the AER's estimate is based are inconsistent between firms and over time;
- The AER's estimate ignores important information about the precision of beta estimates (i.e., the AER does not consider standard errors, which is inconsistent with standard statistical and econometric practice);
- The AER's estimate ignores important information about the reliability and informativeness of beta estimates (i.e., the AER does not consider R^2 statistics, which is inconsistent with standard statistical and econometric practice); and
- The AER's estimate ignores the issue of bias in beta estimates, which is inconsistent with standard statistical and econometric practice and with the practice of commercial beta services.

The SFG report also concludes that the regulatory estimate of 0.8 is commercially implausible. The reasons for this conclusion include:

- The approach on which the 0.8 estimate is based produces implausible estimates over time. When that approach is applied to other industries, it produces estimates that vary so wildly over time that those estimates cannot possibly be a reliable reflection of systematic risk;
- An equity beta estimate of 0.8 (together with a market risk premium estimate of 6.0%) produces an estimate of the required return on equity that is lower than the return on equity that investors could reasonably expect to receive from

comparable firms. The allowed return on equity based on an equity beta estimate of 0.8 provides equity holders in the benchmark firm with a return of 9.3% from dividends and capital gains.[49] This can be compared with a return from dividends and capital gains, from comparable firms, of 11.5% to 12.5%; and

- The present regulatory estimate of an equity beta of 0.8 can therefore be rejected as it is based on analysis that is statistically unreliable and produces outcomes that are commercially implausible.

In addition the sample of data that forms the basis of the AER's empirical estimates of beta consists of returns for only six firms, none of which is a 'pure play' gas distribution or transmission business. In addition, of these six firms, data is only available for two for the short period specified by the AER. The AER has stated that:

> '…the AER considers that a sample of four firms is unlikely to provide a robust equity beta estimate....'[50]

However it then proceeded to rely on estimates that are based on analysis of four firms or less for the majority of the sample period.

Moreover, the AER explicitly instructed its consultant to limit the analysis to a period of somewhat more than six years, even though there is evidence that beta estimates based on longer sample periods are statistically more reliable.[51]

The accompanying SFG report concludes that one should only move from the default and previously adopted equity beta of 1.0 to the extent that:

- Appropriate analysis of the available data suggested that a move away from the default of 1.0 is warranted; and

- The resulting equity beta value results in an estimate of the required return on equity that is economically reasonable and commercially plausible in the circumstances.

The AER's 2008 estimate of 0.8 fails both requirements.

APTPPL notes that no statistically reliable evidence of a beta less than one has been advanced as part of the wider regulatory debate on the appropriate beta value.

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[49] For example, using the parameter estimates in the AER's Amadeus Pipeline Final Decision.

[50] AER, Review of the weighted average copst of capital (WACC) parameters – Electricity transmission and distribution network service providers: Final decision, May 2009, p. 255.

[51] See, Gray, S., J. Hall, D. Klease and A. McCrystal, (2009), "Bias, stability and predictive ability in the measurement of systematic risk," *Accounting Research Journal*, 22, 3, 220-236, and Hooper, V.J., K. Ng and J.J. Reeves, (2008), "Quarterly beta forecasting: An evaluation," *International Journal of Forecasting*, 24, 480-489.

Moreover the current returns on debt means that a return on equity using an equity beta of 0.8 is commercially implausible.

The accompanying SFG report concludes that an equity beta estimate of 1.0 does produces an estimate of the required return on equity that is broadly consistent with the prevailing conditions in the market for funds.

APTPPL has therefore concluded that there is no reason to depart from the default estimate of 1.0 for the equity beta, and has adopted this value in determining the appropriate WACC.

6.7 Gamma

Gamma is a parameter used to represent the value that equity investors place on the franking credits created through the payment of company income tax. Australian regulators use gamma to determine the proportion of company income tax that does not need to be included in a regulated firm's annual revenue requirement.

The value of gamma has recently been the subject of an appeal to the Australian Competition Tribunal by ETSA Utilities, Ergon Energy and ENERGEX. On 13 May 2011, the Tribunal concluded that based on the material before it a value of 0.25 was the best estimate of gamma.[52] APTPPL proposes to adopt the same value for gamma as that determined by the Tribunal.

Gamma is estimated as the product of two further parameters, namely:

- The fraction of imputation credits created that are assumed to be distributed to shareholders (the distribution rate or 'F'); and
- The market value of imputation credits distributed as a proportion of their face value (theta or 'θ').

Each of these parameters is addressed in turn below.

6.7.1 Distribution rate

The distribution rate is a measure of the proportion of franking credits distributed to shareholders. When a company distributes all of its profits in a year as dividends, its shareholders receive a full payout of all imputation credits created in that year. However, companies often do not distribute all of their profits and instead reinvest a portion of their profits, and so have a distribution rate of less than one.

The actual distribution rate will vary from company to company. Consistent with regulatory practice, rather than forecasting the distribution rate for RBP, APTPPL

[52] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, Paragraph 42.

have adopted a distribution rate equal to the historical average of all Australian companies.

The historical market average distribution rate of 0.71 was estimated by Hathaway and Officer (2004).[53] Using Australian Tax Office (ATO) statistics Hathaway and Officer report that over the period from 1988 to 2002 net company tax collected was $265 billion and that $77 billion in imputation credits were retained by Australian firms. As a result, $188 billion or 71 per cent of imputation credits created during this period were distributed.

A more recent study by NERA Economic Consulting, also using ATO statistics, showed that 68 per cent of all credits created were distributed over an 11 year period (1996/97 to 2006/07).[54]

Based on this evidence APTPPL proposes to adopt a payout ratio of 0.7. Note that a distribution rate of 0.7 is consistent with that adopted by the Australian Competition Tribunal in October 2010.[55]

6.7.2 The value of theta

Theta is the market value of imputation credits distributed as a proportion of their face value. APTPPL considers that the best evidence to the market value of distributed imputation credits is derived from dividend drop-off studies.

Dividend drop-off studies estimate theta by observing the price of stocks immediately before and just following the accrual of a dividend (i.e., when a stock goes ex-dividend). The most comprehensive and recent dividend drop-off study was produced by SFG Consulting in March 2011.[56] The Australian Competition Tribunal cited this study and concluded that:[57]

> 'The Tribunal is satisfied that SFG's March 2011 report is the best dividend drop-off study currently available for the purpose of estimating gamma in terms of the Rules. Its estimate of a value of 0.35 for theta should be accepted as the best estimate using this approach. In particular, the Tribunal cannot accept the submission of the AER that either minor issues in the construction of the database or multicollinearity argue for giving the SFG study less weight and the Beggs and Skeels study some weight. The Beggs and Skeels study, despite not being subjected to anything like the same level scrutiny, is known to suffer by comparison with the SFG study on those and other grounds.

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53 Hathaway N. and Officer, B, *The Value of Imputation Tax Credits*, Working Paper, 2 November 2004, pg 4.

54 NERA, *Payout Ratio of Regulated Firms - A report for Gilbert + Tobin,* 5 January 2010, pg 6.

55 Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9, Paragraph 4.

56 SFG, *Dividend drop-off estimate of theta*, 21 March 2011.

57 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, Paragraphs 29 and 30.

> Moreover, the fact that in its earlier reasons the Tribunal found no error in the AER having relied on the Beggs and Skeels study is not to the point. The proceedings since then have been largely designed to render that study, along with the earlier SFG study, obsolete for the purpose of setting a value for gamma – and have done so.'

Therefore, APTPPL proposes to adopt a value for theta of 0.35 consistent with that adopted by the Australian Competition Tribunal in May 2011.

6.7.3 Proposed value of gamma

APTPPL proposes value of gamma of 0.25, this is calculated as the product of:

- A distribution rate ('F') of 0.7; and
- The market value of theta ('θ') of 0.35.

This matches the value adopted by the Australian Competition Tribunal in May 2011.[58]

6.8 Taxation rate

A corporate income tax rate of 30% has been proposed for the access arrangement period, in line with current Australian tax law.

6.9 Expected Inflation

Consistent with regulatory precedent, inflation has been forecast over a ten year horizon thereby matching the term of the risk free rate. We propose to estimate forecast inflation on the basis of the latest Reserve Bank of Australia (RBA) expectations as published in their Statement on Monetary Policy.

The RBA currently publishes a number of forecasts of the Consumer Price Index (CPI), including:

- CPI Inflation (i.e., headline inflation);
- Underlying inflation;
- CPI inflation, excluding the effect of the carbon price; and
- Underlying inflation, excluding the effect of the carbon price.

[58] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, Paragraph 42.

To maintain compatibility with the pricing adjustment mechanism (i.e., the CPI-X price path) that adjusts prices annually for the change in headline CPI less the 'X' factor, the RBA forecast of CPI inflation (i.e., headline CPI) has been used.

Inflation forecasts can change over time. In line with Australian regulatory practice we expect that the forecast inflation estimate would be updated at the time of the AER's final decision. For indicative purposes for this submission we have calculated forecast inflation based on the inflation expectations contained in the RBA Statement on Monetary Policy: August 2011 as set out in Table 6.1.

Table 6.1: Inflation rate forecast (%)

	Jun-12*	Jun-13*	Jun-14**	Jun-15**	Jun-16**	Jun-17**	Jun-18**	Jun-19**	Jun-20**	Jun-21**	Geometric average
Inflation forecast	2.50	3.75	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.62

* Source: RBA Statement on Monetary Policy, August 2011, p. 73.

** Source: Midpoint of the RBA target range for inflation over the economic cycle.

6.10 WACC estimate

Based on the parameter estimates set out in this chapter, the resulting indicative estimate of the nominal post-tax WACC to apply to the RBP is summarised in Table 6.2.

Table 6.2: Proposed WACC

Parameter	Estimate
Risk free rate	4.25%
Forecast inflation	2.62%
Real risk free rate	1.59%
Gearing (debt to value)	60%
Debt risk margin	4.31%
Nominal pre-tax cost of debt	8.56%
Market risk premium	7.0%
Equity beta	1.0
Nominal post-tax cost of equity	11.25%
Gamma	0.25
Nominal post-tax WACC	9.63%

7 Taxation

This section outlines the treatment afforded to tax in this proposed AA, the roll forward of the Tax Asset base, and the calculation of the regulatory tax allowance.

7.1 Estimation of a tax asset base

TAB was estimated by the AER at the last review based on the AER's detailed analysis of capital expenditure over the 20 years prior to the establishment of the Initial Capital Base.

The ACCC established the opening TAB as at 12 April 2006 at $93.822m million.

7.2 Standard tax lives of assets

Standard and remaining tax asset lives are subject to an ATO statutory cap that has been used in preparing the APTPPL TAB. The statutory and remaining tax asset lives are reported in Table 5 2 above.

7.3 Tax Asset Base Roll Forward 2006-2012

Consistent with the roll forward of APTPPL's capital base from 1 July 2012 to 30 June 2016, APTPPL proposes to adopt tax asset base roll forward schedule that has been calculated using forecast capital expenditure. Similarly, APTPPL proposes that the depreciation schedule for establishing the opening tax asset base at 1 July 2017 will be based on forecast capital expenditure as demonstrated in Table 5.4 above.

In contrast to the RAB roll forward, there is no indexation applied to the TAB. This is consistent with the tax legislation.

Table 7.1: Historical TAB Roll forward

$000 (nominal)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Opening TAB	93.82	90.04	115.98	105.67	96.28	94.06
Capital expenditure	2.57	32.65	2.72	4.13	11.85	55.67
Tax depreciation	-6.35	-6.71	-13.03	-13.51	-14.07	-15.01
Total	90.04	115.98	105.67	96.28	94.06	134.72

7.4 Tax Asset Base Roll Forward 2012 to 2017

Table 7.2: Forecast TAB Roll forward

$m (nominal)	2012/13	2013/14	2014/15	2015/16	2011/12
Opening TAB	134.72	121.25	113.58	103.87	94.73
Capital expenditure	4.10	4.70	3.60	3.93	3.40
Tax depreciation	17.56	12.37	13.31	13.07	12.51
Total	121.25	113.58	103.87	94.73	85.62

7.5 Corporate income tax building block

Consistent with rule 76(c), APTPPL proposes a corporate income tax building block as set out in Table 7.3. This amount has been calculated using the AER's Post Tax Revenue Model.

Table 7.3: Corporate income tax building block 2012/13 to 2016/17

$m ($2011/12 real)	2012/13	2013/14	2014/15	2015/16	2016/17
Tax Payable	2.70	5.01	5.06	4.98	4.80
Less Value of Imputation Credits	-0.67	-1.25	-1.26	-1.24	-1.20
Tax allowance	2.02	3.76	3.79	3.73	3.60

7.6 Tax Losses

APTPPL has modelled the regulatory tax position for the period from 1 July 2006 to 30 June 2012 in a manner that is consistent with the AER's post-tax revenue model to determine the potential tax losses that are attributable in that period. This modelling confirms that there are no tax losses attributable which should be carried forward at 30 June 2012.

8 Operating expenditure

8.1 Historical operating expenditure 2007-12 AA Period

This Section of the Access Arrangement Submission describes APTPPL's historical non-capital costs during the current Access Arrangement period (2007-12 AA period). This information is provided in accordance with Rule 72(1)(a)(ii).

Rule 69 of the National Gas Rules 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".

In addition, Section 24 of the National Gas Law states that "A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in:

(a) Providing reference services; and

(b) Complying with a regulatory obligation or requirement or making a regulatory payment."

For the purpose of this Access Arrangement Submission, non-capital expenditure has been divided into controllable costs and non-controllable costs. These are described below.

8.1.1 Controllable Costs

Controllable costs are those costs incurred by APTPPL in the operation of the RBP, over which APTPPL is able to exert a degree of influence in terms of both frequency and magnitude of the costs. This control is tempered, however, by regulatory obligations and other considerations of efficiency and prudency. Typical controllable costs occur in the areas of labour, contractors engaged in the maintenance and operation of the pipeline and other operating costs.

Labour

Labour costs include staff salaries and wages and other employee related costs attributable to the management, maintenance and operation of the pipeline, pipeline right of way, pipeline facilities, compressor stations, SCADA and communications systems and regulation, metering and gas measurement equipment. Typical maintenance activities may include planned maintenance (which is systematic maintenance undertaken to minimise whole of life costs and prevent asset failure),

and unplanned (or corrective) maintenance or repair activities, where failed assets are returned to working order.

The majority of employees are covered by a workplace agreement. This agreement determines the terms and conditions of employment for a fixed period of time.

Contractors - Operations and Maintenance

Contractor costs include costs of contracted services associated with operating and maintaining the pipeline.

Other Operating Costs

Other operating and maintenance costs include materials, management and consultancy fees and support activities costs such as procurement, stores, property, computing & communication, and operation of APTPPL vehicles.

8.1.2 Non-Controllable Costs

Non-controllable costs are those necessarily incurred by APTPPL but over which APTPPL has little or no direct control. Non-controllable costs may include costs imposed by external regulatory bodies. Specifically, non-controllable costs include insurance, government taxes and licence fees, and the corporate overheads allocated to APTPPL by its parent company, APA Group.

Insurance

Insurance costs are the premiums associated with the industry special risks (ISR), public liability, travel and motor vehicle insurance as quoted by APA Group's independent insurance broker.

Government Taxes and Licence Fees

APTPPL pays a variety of fees and charges to government bodies, including Queensland Department of Environment and Resource Management (DERM) and Department of Employment, Economic Development and Innovation (DEEDI). These fees and charges are set by the relevant government body and are non-negotiable.

Corporate Overheads

Corporate overheads are those charges necessarily allocated to APTPPL by its parent company APA Group to attribute APTPPL's share of the costs associated with the management and administrative functions provided by APA Group and are discussed in detail in Section 8.4.

8.1.3 Comparison between actual and ACCC approved operating expenditure for the 2007-12 Access Arrangement period.

Table 8.1 shows the operating expenditure approved by the ACCC in the 2007 Access Final Determination Final Approval.[59]

Table 8.1: ACCC Approved Expenditure 2007-12 AA Period

($'000 nominal)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Wages & Salaries	848	906	947	977	1,012	1,040
APT Other Corporate Costs	1,192	1,243	1,274	1,310	1,354	1,388
Operations and Maintenance, Insurance, License Fees and Security	6,473	6,689	6,795	6,931	7,100	7,215
Total	8,513	8,838	9,015	9,218	9,467	9,644

Extrapolation of approved expenditure to 2011/12

Although the previous Access Arrangement expires in April 2012, approved expenditure figures are only up to 2010/11[60]. To enable a comparison against forecast 2011/12 costs, approved figures have been extrapolated to 2011/12. The basis used for this extrapolation is explained below:

- Salaries and Wages were increased by 0.28% in real terms based on similar increases in approved expenditure over the previous two years; FY10 & FY11;
- Corporate Costs were kept at the same value in real terms throughout the AA period; this was continued for 2011/12;
- Operations & Maintenance costs were decreased by 0.86% in real terms based on same decrease being applied for each year of AA period; and
- These figures have then been converted to nominal using a forecast CPI increase of 2.5% for FY12.

APTPPL's actual operating costs for 2007-12 AA period are shown in Table 8.2. These costs are based on actual costs for financial years 2007 to 2012.

[59] Australian Competition & Consumer Commission, *Access Arrangement Information for Roma to Brisbane Pipeline: APT Petroleum Pipelines Ltd,* April 2007, Table 8

[60] Final Approval and Access Arrangement Information.

Table 8.2: APTPPL Actual operating Costs 2007-12 AA Period

($'000 nominal)	2006/07[61]	2007/08	2008/09	2009/10	2010/11	2011/12F
Wages & Salaries	-	2,316	4,201	4,323	5,234	5,473
APT Other Corporate Costs	2,093	2,117	2,306	3,016	3,393	3,603
Operations and Maintenance, Insurance, License Fees and Security	7,601	3,320	2,393	2,317	5,575[62]	2,789
Total	9,694	7,752	8,900	9,657	14,202	11,865

There is a significant increase in actual operating costs in 2010/11 and to a lesser extent, 2011/12, due predominately to costs associated with flood damage repair works. These works are explained in detail in Attachment 8.1.

It is important to note with regard to APTPPL's operating costs that APA Group changed the accounting systems for APTPPL from Finance One to Oracle during the 2010 financial year. This change was made to achieve common accounting systems and processes across APA Group's businesses Australia wide. This change means that there are some changes to the presentation of financial data across the 2007-12 AA period.

Table 8.3 presents the variation in approved and actual operating costs for the 2007-12 AA Period for each cost category.

[61] APT Petroleum Pipelines Ltd Regulatory Accounting Statements

[62] This increase is caused primarily by the damage to the RBP caused by the 2011 Queensland floods. See below for adjustment to base year costs.

Table 8.3: Variations between Actual and Approved Operating Costs

($'000 nominal)	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Salaries & Wages Actual	-	2,316	4,201	4,323	5,234	5,476
Salaries & Wages Approved	848	906	947	977	1,012	1,040
Salaries & Wages Variance	(848)	1,410	3,254	3,347	4,222	4,432
Operating & Maintenance, Insurance, License Fees and Security Actual	7,601	3,320	2,393	2,317	5,575	2,789
Operating & Maintenance, Insurance, License Fees and Security Approved	6,473	6,689	6,795	6,931	7,100	7,215
Operating & Maintenance, Insurance, License Fees and Security Variance	1,128	(3,369)	(4,402)	(4,613)	(1,525)	(4,426)
Net Operating Costs	281	(1,959)	(1,148)	(1,267)	2,697	6
Corporate Costs Actual	2,093	2,117	2,306	3,016	3,393	3,603
Corporate Costs Approved	1,192	1,243	1,274	1,310	1,354	1,388
Corporate Costs Variance	900	874	1,032	1,706	2,039	2,215
Total Operating Actual	9,694	7,752	8,900	9,657	14,202	11,865
Total Operating Approved	8,513	8,838	9,015	9,218	9,467	9,644
Total Operating Variance	1,181	(1,085)	(115)	439	4,736	2,221

Items impacting the comparison of historical forecast and outturn opex are discussed below.

Pipeline Management Agreement

At the commencement of the previous Access Arrangement period, a Pipeline Management Agreement (PMA) existed between Agility Management Pty Limited (Agility) and APTPPL.

Agility were contracted to provide services including all asset management, operations and maintenance work required for the safe, efficient and compliant operation of the RBP. The amount paid to Agility Management included the costs of

direct operations, operations support, engineering support, pipeline maintenance and easement management.

APTPPL negotiated on a commercial basis to terminate the PMA effective October 2007 and perform these functions in-house. Due to the nature of the agreement, detailed operating and maintenance cost data is not available prior to this time.

The PMA contract termination is discussed in more detail in Attachment 4.3.

Short Term Trading Market (STTM)

The Short Term Trading Market (STTM) is a wholesale market designed to facilitate short term gas trading using market driven short term (daily) prices[63]

The STTM operates in conjunction with existing underlying gas supply, transportation and network contracts. The physical operation of pipeline and network assets is maintained by owners of the infrastructure.

The QLD STTM for gas delivered into Brisbane is planned to commence on 1 December 2011. In preparation, APTPPL commenced STTM trials in August 2011.

The STTM is being managed by the Australian Energy Market Operator (AEMO) and APTPPL has a key role as the provider of information to the STTM concerning gas flows to and from the Brisbane hub. All gas that flows to delivery points from Riverview to Gibson Island will be priced through the STTM.

The impact on APTPPL is significant as it must supply forecast pipeline capacity for gas flows into the Brisbane hub for three days ahead of the gas day and allocation data for gas delivered to individual market participants within hours of the end of the gas day. APTPPL also has to allocate Market Operator Service (MOS) gas each day, where there is a difference between nominated gas and delivered gas. This information impacts the STTM price outcomes which affect the price that participants trade gas. APTPPL has been required to implement systems and processes so that it can provide accurate and timely information. APTPPL is also required to resource appropriately for the provision of this data every day of the year.

Lytton Lateral expansion

The existing Allgas distribution network could no longer provide for increasing gas demand in the Lytton industrial area of Brisbane. In 2009 APTPPL secured a long term contract with AGL to transport 4 TJ/d of gas to the Caltex oil refinery in Lytton. To provide for that contract a new extension to the RBP was constructed into the Lytton area.

[63] AMEO website http://www.aemo.com.au/STTM/sttm.html.

In 2010 the 6.2 km of 200mm steel pipeline with associated infrastructure was constructed, at a cost of $9.06M dollars.

The new lateral and associated facilities are operated in accordance with APTPPL's standard management practices for assets of this type. This increase in operational expenditure is an incremental cost to APTPPL operational expenditure for the RBP.

8.2 Forecast operating expenditure

8.2.1 Forecast methodology and assumptions

This Section of this Access Arrangement Submission addresses the requirement of Rule 72(1)(e) for the access arrangement information to include a "forecast of operating expenditure over the access arrangement period and justification for the forecast".

Rule 91 specifies that "Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services".

For the purpose of forecasting operating expenditure, APTPPL has used the base year methodology. This methodology involves the following steps:

- Selection of an appropriate base year in which to measure costs (Section 8.2.2);
- Modification of the base year costs to ensure that all costs required for future operation of the pipeline are added to the base year costs, and all costs in the base year costs which are not relevant to future operation of the pipeline are subtracted from the base year costs (Section 8.2.4);
- Modification of base year costs as required to reflect change in operation and maintenance requirements of the pipeline, additional facilities required to supply gas to consumers, and increased loads from existing consumers (Section 8.2.5.5); and
- Modification of the base year costs to reflect changes in input costs anticipated over the access arrangement period (Section 8.2.5.1).

It is assumed that there are no planned productivity improvements that will have a material impact on RBP operational expenditure during the Access Arrangement period beyond those already included in cost escalators applied.

8.2.2 Determination of the base year

APTPPL has used its 2010/11 actual operating expenditure as its base year for estimating operating costs in the access arrangement period. APTPPL chose this year as it is the most recent complete year to the access arrangement period, and finalised audited accounts are available for this year.

8.2.3 Benchmarking and Efficiency

Rule 91 provides that "operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services."

Implicit in this Rule is a requirement for the business to demonstrate that it meets benchmark levels of efficiency in comparison with other comparable pipelines

Meaningful basis of benchmarks

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

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

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

The best indicators use either pipeline length or a replacement value, such as ORC as a proxy for replacement costs, RBP has used a combined measure of the length of the pipeline and its size. The operating expenditure benchmarks used in this access arrangement revision proposal are:

- $ cost per km of pipeline length; and
- $ cost per mmkm of pipeline diameter x length.

The costs benchmarked below reference 2010/11 operating expenditure for the RBP reported in Table 8.2 of this submission.

Comparator Pipelines

The following pipelines were used as comparators given the availability of regulatory decisions on the efficient operating expenditure of those pipelines.

- GasNet/VENCorp;
- Moomba-Adelaide Pipeline;
- Dampier-Bunbury Natural Gas Pipeline;
- Moomba Sydney Pipeline;
- Goldfields Gas Pipeline; and
- Amadeus Gas Pipeline.

To allow meaningful comparisons, the performance measures discussed here reflect operating expenditure as reflected in various regulatory decisions. This expenditure is not completely comparable due to differing treatments of inflation and corporate costs, and the different ages, locations and physical characteristics of the pipelines.

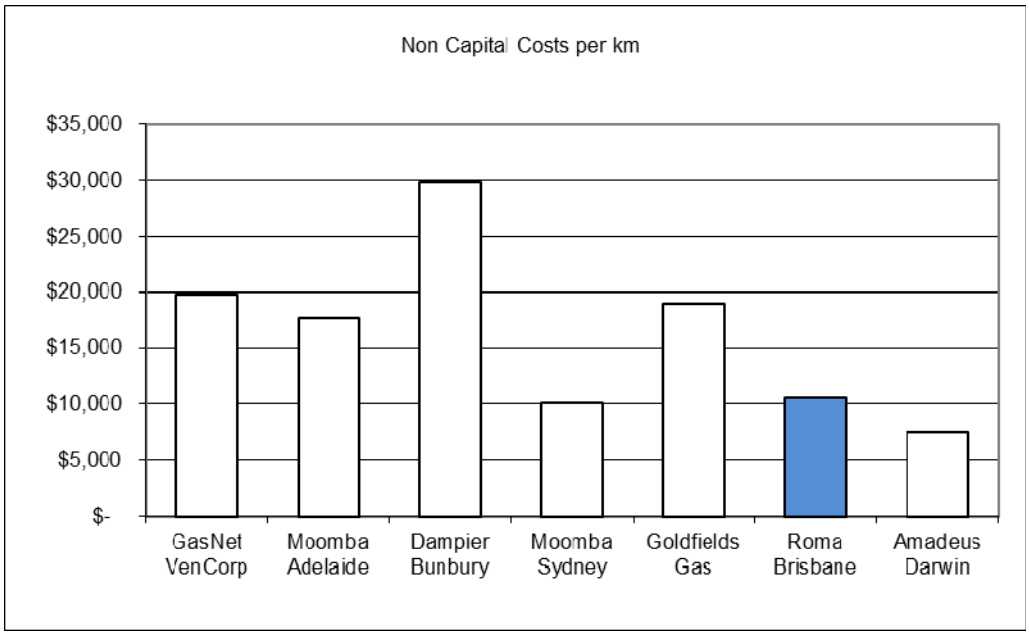
8.2.3.1 *Key findings*

RBP's costs are lower than most of the benchmarked businesses.

Operating expenditure cost per km

For operating expenditure per kilometre of pipeline route the RBP's costs are amongst the lowest of comparator pipelines.

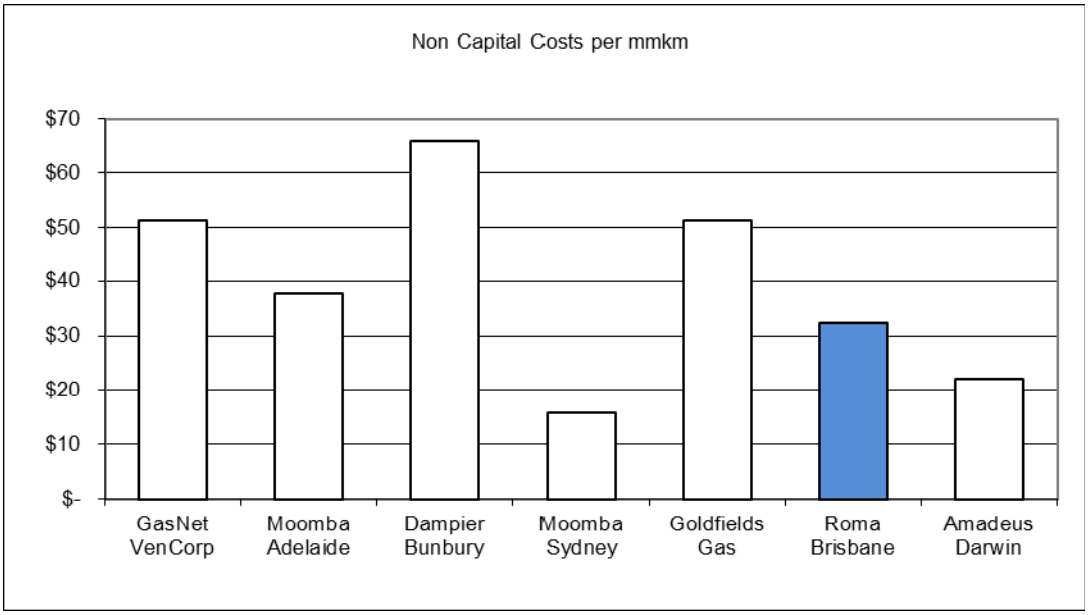
Figure 8.1 Operating expenditure per kilometre



Operating expenditure as a percentage of mmkm

Similarly, on the basis of comparing operating expenditure cost per kilometre of pipeline route multiplied by the size of the pipeline, the RBP performs in line with other Australian pipelines.

Figure 8.2 Operating expenditure per mmkm



Key performance indicators for APTPPL forecast operating expenditure are shown below in Table 8.4

Table 8.4: Key Performance indicators ($2010/11)

Indicator	Unit	2011/12	2012/13	2013/14	2014/15	2015/16
Total Operating Costs per km	$/km	12,490	12,930	13,393	14,047	14,970
Total Operating Costs per mmkm	$/mmkm	38.6	39.9	41.4	43.4	46.2

Based on this analysis, APTPPL's operating expenditure for the RBP appears to compare well with that of other pipelines, suggesting that it at least meets benchmark levels of efficiency, as required under Rule 91.

8.2.4 Adjustments to base year costs

The 2010/11 base year requires adjustment in order for it to accurately reflect expected future operating expenditure on the pipeline. Adjustments relate to activities undertaken in that year that were not 'typical' of APTPPL's operating expenditure in other years.

The first necessary adjustment to the base year relates to the extraordinary level of repair work undertaken in that year in response to severe flooding in South east Queensland during December 2010 and January 2011. These works and related costs are described in detail in attachment 8.1.

The second series of adjustments relates to expenditure in 2010/11 that is either non-routine, or which relates to projects that are not undertaken on an annual basis. APTPPL has removed non-routine expenditure associated with three operating expenditure projects from its base year detailed below.

8.2.4.1 *The Queensland Floods*

Prolonged and intensive rainfall over large areas of Queensland, coupled with already saturated catchments, led to significant flooding in Queensland in December 2010 and January 2011. Thirty-five people died in the floods. More than 78 per cent of the state (an area bigger than France and Germany combined) was declared a disaster zone, with over 2.5 million people affected. Some 29,000 homes and businesses suffered some form of inundation. The Queensland Reconstruction Authority has estimated that the cost of flooding events alone will be in excess of $5 billion.[64]

Major flood peaks were observed in the Condamine River at Warwick and the Myall Creek at Dalby. The Condamine River peak affected about 45 homes and forced the evacuation of the township of Condamine, close to the Arubial station. The Myall Creek flood split the town of Dalby in two and inundated some 100 properties.

On 10 January, heavy rainfall was recorded in the Toowoomba area. This rainfall resulted in flash flooding in the centre of the city, killing two people. The Lockyer Valley was also subjected on that afternoon to unprecedented flash floods following heavy rainfall across almost all catchments in the Upper Lockyer Valley. Flood water flowed through the Upper Lockyer Valley, causing severe damage in Murphys Creek, Withcott, Helidon and Grantham, finally reaching Gatton.

The rainfall produced flash floods in Murphys Creek, Rocky Creek, and the upper and middle reaches of Lockyer Creek, which gained width and velocity as they moved downstream.

[64] Queensland Floods Commission of Inquiry, *Interim Report* August 2011 p20, Attachment 8.2

Upstream of Helidon, Rocky Creek delivered its flows to Lockyer Creek. DERM undertook a survey in the weeks following the flood event, concluding that the Helidon peak was approximately 13.88 metres. [65]

At the township of Murphys Creek, flooding began in the early afternoon. A witness who lived at Upper Lockyer near the town said that he saw a wave of water in the creek breaking in the distance; the force of the approaching water was ripping out trees in its path. The level of the creek rose about 12 metres in 12 minutes[66].

Impact on system

Four sites suffered major damage, requiring an immediate response, due to complete submersion or washout by floodwaters. This included two stations that were submerged and two large areas of exposure of the pipeline. At one of these sites, a landslip required a section of the pipeline to be taken out of service due to a loss of containment.

A further six sites experienced significant washouts and there was substantial erosion across multiple smaller sites along the pipeline.

Operating pressures in both the DN400 and DN250 pipelines were reduced while damage was being assessed however sufficient supply to meet customer demand was generally maintained during this time.

APTPPL response

In accordance with AS2885.3, APTPPL deployed resources as required in response to the floods, including;

- An initial, immediate response to ensure safety and security of supply;
- Temporary compressor modifications to provide continuity of supply to meet contracted customer demand;
- Performed engineering assessments in accordance with AS2885.3 to ensure integrity of the pipeline;
- Safety management study conducted to systematically assess and address the risks associated with the flood damage; and
- Substantial remedial works were required at several sites during January to June 2011. Further remedial works continued through to September 2011 to address erosion issues along the pipeline.

[65] Queensland Floods Commission of Inquiry, *Interim Report* August 2011 p236, Attachment 8.2
[66] Queensland Floods Commission of Inquiry, *Interim Report* August 2011 p236, Attachment 8.2

Damage and associated costs

Details of damage, APTPPL's initial emergency response and remedial works and associated costs are contained in Attachment 8.1. Wherever possible these costs have been tracked separately. It is anticipated that the majority of these costs, except for ordinary time labour costs, will be recovered through insurance.

Table 8.5 below provides a summary of flood impact costs on base year;

Table 8.5: Summary table of flood impact costs on base year

Adjustment	Value ('000 $2010/11)
Actual repair costs[67]	(4,327)
Other flood related costs	(56)
Labour costs (not recoverable from insurance)[68]	575
Net cost adjustment for flood impact	(3,809)

Non-routine projects

- Geotechnical Risk Study – completed in 2010/11 costing $102,013;

  Toowoomba escarpment – The RBP DN250 runs down the Toowoomba escarpment at an acute angle, at one point crossing under a railway line through steel casing. Annual survey data and measurements taken by APAPPL staff indicated the steel casing was slipping down the escarpment. Survey data also indicated little movement of the pipeline. External consultants were engaged to assess and advise on direct threats to the pipeline, producing a management plan for the escarpment and risk assessment of pipeline failure due to land slippage. A further, detailed study was conducted to investigate, assess and provide recommendations regarding stresses and strains on the pipeline at the same location.

- ROW Signage replacement – completed in 2010/11 costing $81,000

  Right of Way (ROW) signage is intended to provide a visible indication of the existence of a pipeline in the vicinity and warn of possible dangers. It is desirable

[67] This amount includes a provision for repairs works that are yet to be completed as at 30 June 2011

[68] These costs represent the costs on internal APTPPL labour that was diverted from other pipeline operation activities to deal with the flood damage repairs.

to maintain a line of sight so that from any point on the right of way a sign is visible in either direction[69].

These markers are inspected regularly to ensure that lettering and numerals have not faded and all markers are in a good state of repair. Damaged markers must be replaced to ensure that the location of the pipeline is properly marked at all times.[70]

During 2010/11 a substantial number of these markers required replacement to ensure the signage displayed correct contact information, in accordance with AS2885. It is not anticipated that this level of expenditure would be required on an annual basis to maintain compliance and has therefore been removed from base year costs.

- DEEDI compliance – completed in 2010/11 costing $42,180

  APTPPL engaged an external consultant to undertake a Hazard and Escalation Risk Assessment for the Wallumbilla Receipt Station.

  The assessment included the identification and assessment of hazards and risks of escalation at the APTPPL Group Receipt Station from a fire or explosion at adjacent properties at the Wallumbilla Hub. This was a result of a request from the QLD Department of Employment, Economic Development and Innovation (DEEDI).

  The objective of this hazard and escalation risk assessment was to examine the hazards and risks associated with the natural gas receipt station at Wallumbilla. Through the evaluation of consequence of the major hazards at facilities surrounding the station, the potential for an incident to impact on the station and cause escalation damage was determined. The likelihood of any hazardous incident(s) was estimated and the resulting risk was compared with established risk criteria to provide a risk assessment. It is not anticipated that this level of expenditure would be required on an annual basis to maintain compliance and has therefore been removed from base year costs.

The resulting base year operating costs used for the purposes of forecasting expenditure in the access arrangement period is $10.168 million. These adjustments are summarised in Table 8.6.

[69] APA Group, *Management Procedure: ENG 1-06 ROW Signage & Marking,* January 2011

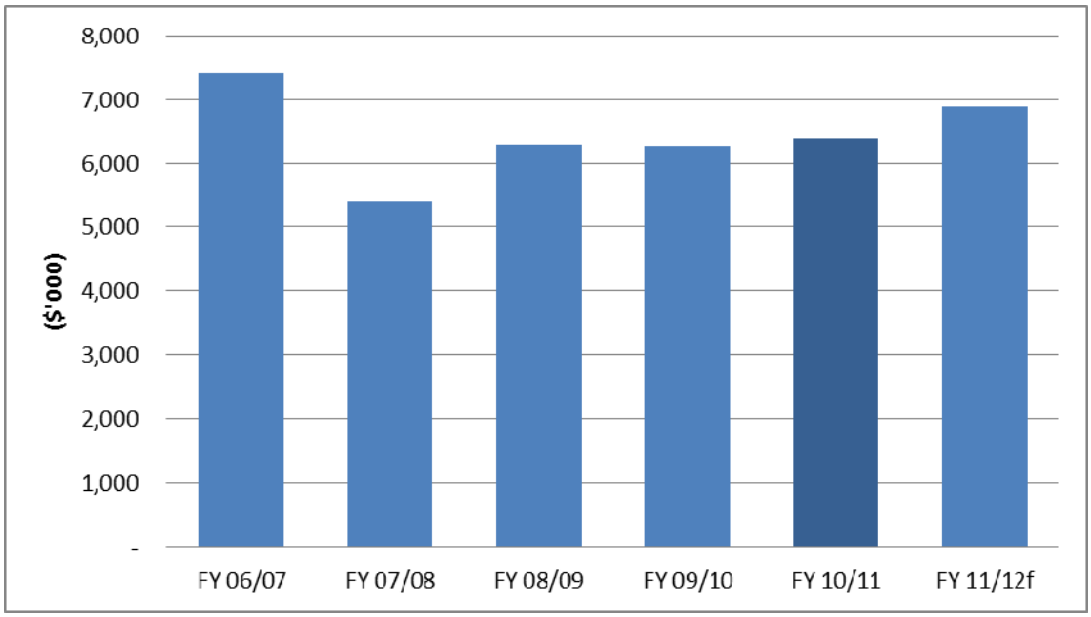
[70] APA Group, *Management Procedure: MGT 6-11 Easement Maintenance*, April 2009

Table 8.6: Summary table of base year adjustments and step changes

Adjustment	Value ('000 $2010/11)
Unadjusted operating expenditure base year	14,202
Flood related adjustments	(3,809)
Non routine projects adjustments	(225)
Base year business as usual	10,168

This includes $6.384 million in controllable costs which are compared to actual (unadjusted) controllable costs in the other years of the earlier access arrangement period in Figure 8.3 below.

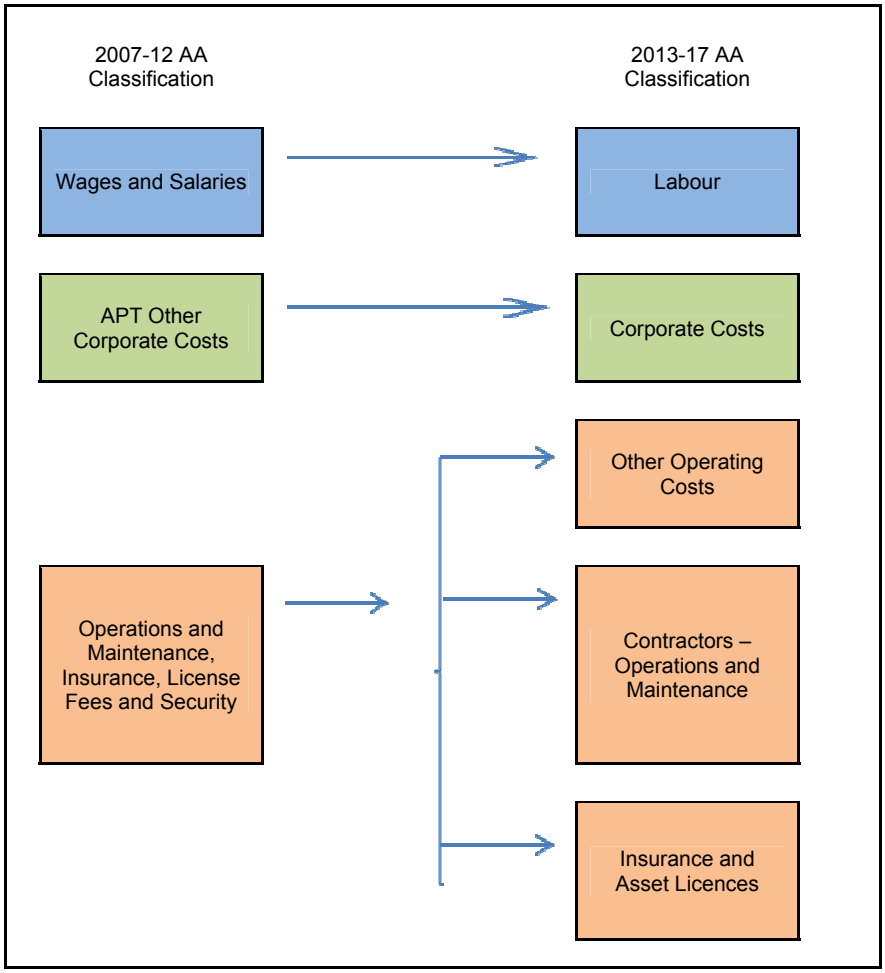
Figure 8.3: Adjusted base year 2010/11 controllable costs compared to other years in the earlier access arrangement period.



8.2.5 Forecast Operating Expenditure

Forecast expenditure for the 2013-2017 AA period has been split into additional categories. These cost categorisation changes better align to how the pipeline is managed and operating costs reported, and also enhance the visibility of key cost drivers. Figure 8.4, below, gives a pictorial representation of the changes in the categorisation of costs in the 2007-12 and the 2016-17 AA periods.

Figure 8.4: Cost Categorisation Changes in AA Periods



8.2.5.1 *Real cost escalation*

For the purpose of calculating the forecast operating costs over the 2013 – 2017 access arrangement period, actual costs for the base year were escalated annually using productivity-adjusted real Average Weekly Ordinary Time Earnings (AWOTE) escalators. Relevant escalators applied to the following labour groups:

- Electricity, Gas and Water (EGW); Gas Network Related, Real Adjusted Productivity EGW AWOTE – Queensland; and
- General Labour (made up of administrative and professional services): Real Adjusted Productivity Weighted Index AWOTE – Queensland.

The methodology for forecasting escalators is set out in the BIS Shrapnel real cost escalation provided at confidential Attachment 8.3. APTPPL intends provide an

update of forecast escalators in that report in response to the AER's Draft Decision to ensure that the most recent available figures are used.

Application of labour escalators

The EGW labour cost escalator has been applied to the associated labour costs of APA Group staff that work directly and/or indirectly on the construction, maintenance, design and operation of the pipeline.[71] Under this application, costs equating to approximately 83% of full time equivalent (FTE) RBP staff have been escalated using EGW indices.

General labour is a weighted labour cost escalator capturing corporate-type functions. This group is made up of a mix of administrative support services staff and professional staff such as accountants, lawyers and IT professionals. APA Group has calculated that 10% of corporate staff are in administrative support type roles, while the remainder are professional staff. BIS Shrapnel has applied this weighting to derive the General Labour escalator.[72] The remaining labour costs have been escalated using this index.

Further confidential information relevant to APA Group's current Enterprise Bargaining Agreement negotiations are provided at Attachment 8.4 This information is relevant to the EGW and General Labour categories.

Use of AWOTE measure

APTPPL considers that use of the AWOTE measure is a more appropriate measure to capture labour costs than using the AER-preferred measure being the Labour Price Index (LPI). As described in more detail in the BIS Shrapnel Real Cost Escalation Report provided at Attachment 8.3 the LPI is a measure of underlying wage inflation in the economy or in a specific industry, as the LPI measures changes in the price of labour, or wage rates, for specific occupations or job classifications, which are then aggregated into a measure of the collective variations in wage rates made to the current occupants of the same set of specific jobs. The LPI, therefore, reflects pure price changes, but does not measure variations in the quality or quantity of work performed.

The LPI does not reliably measure the changes in total labour costs which a particular enterprise or organisation incurs, because the LPI does not reflect the changes in the skill levels of employees within an enterprise or industry. As skills are acquired, employees will be promoted to a higher grade or job classification, and with this promotion will move onto a higher base pay. This type of change in the cost

[71] BIS Shrapnel, Real Cost Escalation Forecasts to 2022 – Australia and Queensland, October 2011, p21, Attachment 8.3.

[72] BIS Shrapnel, Real Cost Escalation Forecasts to 2022 – Australia and Queensland, October 2011, p46, Attachment 8.3.

of labour is particularly expected by APTPPL as staff progress through salary increases by gaining competencies through training. Using the LPI figure in respect of APTPPL's labour prices will not capture this important change in the composition of APTPPL's workforce that influences actual labour costs.

The AWOTE captures both base pay rates and changes in base pay level, while the LPI only captures the first element. Basically, promoting employees to a higher occupation or competency level does not necessarily show up in the LPI, but the employer's total wages bill (and average unit labour costs) is higher, as is AWOTE. The AWOTE measure also includes bonuses, incentives, penalty rates and other allowances, which are also part of an enterprises total wage bill.

Given the limited application of the LPI measure, APTPPL does not consider that its use would be consistent with the revenue and pricing principles which provide that the service provider must be given reasonable opportunity to recover at least its efficient costs is providing reference services. As the LPI does not capture compositional changes that contribute to labour costs, as a measure it cannot be expected to provide reasonable opportunity for a service provider to recover efficient costs where these compositional effects are expected to influence labour costs.

Should the AER persist in its position that the LPI is its preferred measure of labour cost changes, then APTPPL submits that it would use the relevant LPI measure set out in the BIS Shrapnel report at Attachment 8.3 APTPPL considers that BIS Shrapnel has applied a methodology in developing its forecasts (for both AWOTE and LPI) that is consistent with the NGR and that the resultant escalators constitute the best forecast or estimate possible in the circumstances.

Productivity Adjustments

Both the EGW and general labour cost indices used in forecasting labour costs incorporate productivity adjustments.[73] APTPPL notes that this incorporates into the forecast an upfront productivity adjustment before productivity gains are realised.

While APTPPL considers that this approach is not necessarily consistent with the operation of incentive regimes that allow service providers to keep for a period the efficiency and productivity gains made, APTPPL also acknowledges that forecast costs must also reflect the costs incurred by a prudent service provider acting efficiently. On balance with these conflicting drivers, APTPPL has determined to adopt productivity adjusted escalators in its forecast.

[73] BIS Shrapnel, Real Cost Escalation Forecasts to 2022 – Australia and Queensland, October 2011, p36, Attachment 8.3

Superannuation

In the 2010-11 Federal Budget,74 the government announced that the superannuation guarantee (SG) rate will gradually increase from 9% to 12% between 1 July 2013 and 1 July 2019. Although these proposed changes have not yet received royal assent and been passed into law, APTPPL has mirrored these increases in the forecast operating expenditure as detailed below in Table 8.7.

Table 8.7: Superannuation Guarantee Rate increases[75]

Year	2013/14	2014/15	2015/16	2016/17
Rate (%)	9.25	9.50	10	10.5

Step and scope changes (discussed below) have been used to describe significant changes to forecast operating costs over the period. Costs resulting from step and scope changes were added in the appropriate year, and escalated annually thereafter.

8.2.5.2 *Labour*

Forecast labour expenditure for the 2013-2017 AA period is detailed in confidential Attachment 8.4 – Forecast Operational Labour Expenditure. As this information has scope to influence current Enterprise Bargaining Agreement negotiations, it has been filed confidentially.

8.2.5.3 *Asset licences and insurance*

Licence fees and other government charges are set by the relevant government body and are non-negotiable.

Insurance costs are as quoted by APA's independent insurance broker and escalated based on their advice[76].

8.2.5.4 *Regulatory costs*

Despite approving the inclusion of Access Arrangement costs as approved capital expenditure in the current AA period[77], the AER has since reconsidered their

[74] Australian Government Budget Document http://www.budget.gov.au/2010-11/content/overview/html/overview_20.htm

[75] Australian Government, *Fact Sheet: Superannuation — increasing the superannuation guarantee rate to 12 per cent,* July 2011

[76] (Confidential) Marsh, RBP Insurance premiums, Attachment 8.5.

[77] Australian Competition & Consumer Commission, *Access Arrangement Information for Roma to Brisbane Pipeline: APT Petroleum Pipelines Ltd*, April 2007, Table 3

interpretation of r. 79 of the NGR, requiring these costs to be now classified as operating expenditure.[78] APTPPL has therefore made an allowance in 2016/17 for costs associated with the preparation of the next Access Arrangement Submission (2017/18 – 2022/23).

Notwithstanding this change in interpretation by the AER, costs incurred in the current AA period have been treated as capital expenditure as they were forecast and approved as such and on that basis, recovered through tariffs and revenue.

8.2.5.5 *Step and scope changes*

Where additional costs are considered to be significant, scope or step changes have been included in this Access Arrangement Submission. These scope and step changes are summarised below.

The relative total effect of these step and scope changes on APTPPL's forecast operating costs may be seen below.

RBP 8 Expansion

This expansion to the Roma to Brisbane Pipeline (RBP) will augment capacity by looping the pipeline to supply additional gas contracts to customers totalling 24TJ/day from 1 July 2012. The current RBP system has insufficient capacity to cater for the additional loads.

The expansion involves the co-ordination and delivery of four projects in conjunction as listed below:

- Metropolitan Looping Phase 1 (MLP1)

  The MLP1 will involve the construction of approximately 6 kilometres of Class 600 DN300 MLP1 between Preston Road, Carina and Paringa Road, Murarrie with a Maximum Allowable Operating Pressure (MAOP) of 10.2 Mpa.

- Construction of an additional C50 Compressor Station at Dalby

  The upgrade of the Dalby Compressor Station will consist of the installation of an additional compressor unit and the construction of ancillary infrastructure, immediately adjacent to the existing compressor station footprint.

- RBP DN400 Maximum Operating Pressure (MOP) upgrade

  Any increase in operating expenditure related to the MOP upgrade is immaterial for the purposes of this Access Arrangement submission.

[78] AER, *Draft decision – ActewAGL Access arrangement proposal for the ACT, Queanbeyan and Palerang gas distribution network* 1 July 2010 – 30 June 2015, November 2009, p26.

- Ellengrove Gate Station Pig Receiving Facility Upgrade

  Any increase in operating expenditure related to the Ellengrove station upgrade is immaterial for the purposes of this Access Arrangement submission.

The impact on operational expenditure is summarised below in Table 8.8. This amount includes an allocation of shared and corporate costs.

Table 8.8: Operating expenditure impact of step and scope changes

($000 2011/12)	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17
RBP8 Expansion	800	839	878	921	956

8.2.5.6 *Major operational activities*

Risk Assessments

A requirement under AS2885 is that a Safety Management Study (SMS) review is completed for each licensed pipeline at a maximum interval of every 5 years. Sometimes this interval is decreased if anything arises on the asset that requires an earlier review. As an example, a full RBP SMS was last conducted in 2010 (and previously done in 2008) and involved a 5 day workshop, consultant's report and associated action closeout.

8.3 Debt raising costs

Debt raising costs are transaction costs – such as legal fees, underwriting fees or credit rating fees – incurred by the business to hold, raise or refinance debt. Debt raising costs can either be incorporated in the regulatory framework in calculating the appropriate cost of capital, or can be included in the allowance made for operating costs. APTPPL have included debt raising costs in its operating expenditure projection, in line with the AER's approach for NT Gas. APTPPL has not made any allowance for debt raising costs in deriving the WACC to be applied to RBP for the forthcoming access arrangement period.

In calculating debt raising costs, APTPPL has applied the same method and estimates as used by the AER, in its recently published decision for NT Gas.[79]

Based on RBP's opening capital base of $427m and applying a 60 per cent debt gearing ratio, total regulatory debt will be approximately $256m at the start of the regulatory period. The forecast increase in the capital base over the regulatory period implies that total debt will also gradually increase, to reach $289m at 1 July

[79] AER, *NT Gas, Access arrangement proposal for the Amadeus Gas Pipeline – 1 July 2011 – 30 June 2016*, *Final decision* June 2011, p. 95.

2016. The AER's table for estimating debt raising costs has an indicative allowance of two bond issues for all debt levels between $250m and $500m.[80] The debt raising cost for RBP is therefore based on two bond issues. The AER's most recent estimate of the debt raising costs associated with two debt issues is 9.9 basis points per dollar of debt per annum.[81] Debt raising costs have been calculated by the PTRM.

Table 8.9 sets out the estimates of the debt raising costs for each year of the forthcoming access arrangement period.

Table 8.9: Debt raising costs

$million ($2011/12)	2012/13	2013/14	2014/15	2015/16	2016/17
Debt raising costs	0.25	0.24	0.23	0.22	0.22

8.4 Corporate costs

As part of a larger corporate group, certain corporate functions are provided for APTPPL through a centralised corporate body. The functions performed by this centralised group include:

- Chief Executive Officer function;
- Company Secretary function – including annual reporting, general meetings, risk management, compliance management, audit costs, directors costs and general administrative costs;
- Corporate Finance function – including, treasury, tax, investor relations, budgeting, general financial accounting, general management accounting, performance reporting and financial services such general accounts payable and receivable;
- Corporate Commercial function – including general commercial functions;
- Human Resources function – including training, health safety and environment, employee communications, payroll and recruiting;
- IT and Transformation function – including APTPPL specific IT costs;
- Legal and Regulatory function – while general legal and regulatory costs are allocated among the corporate group using the general process, legal and

[80] AER, *NT Gas, Access arrangement proposal for the Amadeus Gas Pipeline – 1 July 2011 – 30 June 2016*, Draft decision April 2011, p. 219.

[81] AER, *NT Gas, Access arrangement proposal for the Amadeus Gas Pipeline – 1 July 2011 – 30 June 2016*, Draft decision April 2011, p. 219.

regulatory matters related to a particular legal action or regulatory process are directly assigned to the particular asset; and

- Projects and Other – including ongoing business improvement projects.

Applicability of corporate costs to APTPPL

Any Service Provider, including APTPPL, needs these functions to be performed in order to meet the following activities and obligations;[82]

- Statutory obligations such as lodging accounts, auditing accounts, reporting to shareholders, maintaining shareholder registries, holding annual general meetings, paying tax, maintaining environmental, safety and regulatory compliance;

- General prudent capital raising activities such as managing investor relations, raising equity via ASX listing and raising debt via debt market activity;

- General prudent human resource management activities such as efficiently recruiting, retaining, training, compensating and managing employees;

- General prudent financial management activities such as operating appropriate internal cost monitoring systems and performance reporting systems and operating invoice payment systems;

- General prudent risk management activities such as insuring assets and operating appropriate internal risk management and reporting systems;

- General prudent IT management activities such as implementing, maintaining and operating company wide compatible IT systems and ensuring IT security is maintained; and

- Ongoing business improvement activities. APTPPL believes that ongoing business improvement activity is implicit in the Rule 91 benchmark of a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice.

APTPPL submits that the costs associated with these functions 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, and that they are necessarily incurred for APTPPL to provide pipeline services.

[82] This listing is not an exhaustive listing of the requirements and obligations which the corporate functions undertake.

It should be recognised that other regulators, notably the ACCC, have previously approved APA Group general corporate costs such as corporate employee salaries, director's fees, rent, office costs, IT costs, communications costs, costs associated with stock exchange listing (eg share registry fees, annual report preparation) and other costs incurred in the operation of a listed business.

Moreover, the AER has accepted this approach in its recent decisions on the APT Allgas AA[83] and that for the NT Gas Amadeus Pipeline:[84]

> The AER accepts NT Gas's forecast corporate overhead costs and considers that they are costs which would be incurred by a prudent service provider acting efficiently as required by r. 91 of the NGR. The AER also considers that the level of corporate overhead expenditure proposed by NT Gas represents the best estimate possible in the circumstances as required by r. 74(2)(b) of the NGR.

Consistent with the above, the corporate costs put forward by APTPPL include costs for senior management and board, company secretary functions including shareholder management and listing, finance including tax, treasury and statutory reporting, information technology, commercial, legal, regulatory, operations management including procurement, asset management and engineering.

8.4.1 Approach

APTPPL is conscious that the AER is concerned about the level and nature of costs allocated to a regulated entity from related companies. APTPPL has taken the following approach to demonstrate that the level of corporate costs allocated to it is reasonable and consistent with the requirements of Rule 91:

- Demonstrate that the aggregate corporate costs were prudently incurred

  The purpose of this stage of the approach is twofold: First, to demonstrate that these costs have been incurred within a corporate governance process that is subject to market disciplines. Second, that these costs were incurred within the spirit of the regulatory "revealed cost approach", in which the incentive of a regulated business (and indeed an unregulated business) is to reduce operating costs to the lowest sustainable level.

- Demonstrate that corporate costs were allocated on a reasonable basis and in a manner consistent with prior years

[83] AER, APT Allgas - Access arrangement proposal for the Qld gas network, 1 July 2011 – 30 June 2016, June 2011, section 7.4 p53 and Table 7.1.

[84] AER, Final decision - N.T. Gas, Access arrangement proposal for the Amadeus Gas Pipeline 1 August 2011 – 30 June 2016, July 2011, section 7.4 and Table 7.2.

The purpose of this stage is to demonstrate that the corporate group does not allocate costs among the operating businesses opportunistically to take advantage of particular price review processes.

- Demonstrate that the amount of costs allocated to APTPPL is not more than would be incurred by a benchmark stand alone firm

  Directly to meet the requirements of Rule 91, APTPPL has commissioned a benchmarking study to demonstrate that the level of corporate costs allocated to APTPPL is not greater than the amount that would be incurred by APTPPL were it a stand alone business.

8.4.1.1 *Aggregate corporate costs prudently incurred*

In preparing its regulatory accounts, APA Group must reconcile to its audited statutory accounts. The audit assurance provided on the corporate accounts demonstrates that the amount of reported corporate costs is as reported.

Inherent in that reported amount is the corporate governance process on the incurrence of those costs. The activities behind these costs are subject to a rigorous budgeting process which ensures that the activities are necessary to operate the business to provide pipeline services, and that the costs of performing these costs are not more than the lowest sustainable cost.

This is consistent with the Australian regulatory "revealed cost" methodology for determining a reasonable basis of non-capital cost forecasts. It is in the interest of any organisation, regulated or otherwise, to reduce its non-capital costs to the lowest sustainable level. This is consistent with the pricing principles encapsulated in Section 24(b)(3) of the National Gas Law.

APTPPL considers that the starting point of this analysis, the audited corporate financial statements, provides evidence that the corporate costs were actually incurred, and that, in conjunction with the corporate governance process, that these costs are at the lowest sustainable level required to provide the pipeline services.

Corporate governance and Board budgeting process

Being incurred at the corporate level, the corporate costs are subject to a rigorous Board review and budget approval process. Some noteworthy points of this process include:

- The corporate costs are from a Board approved budget. This budget is not derived for any regulatory purpose and is independent of any regulatory process. The costs in the budget are based on internal business forecasts and represent a reasonable estimate of future costs. The costs are within the market guidance provided in accordance with ASX listing rules;

- In setting the budget costs the Board is required to act in the interests of APA Group shareholders; it is not in the interests of APA Group shareholders to have excessive costs. As such there are strong corporate governance reasons to assume these costs are prudent and efficient; and

- The incentive to reduce costs is further reinforced by APA Group management incentive schemes. These incentive schemes are driven by a formula, the most readily controlled component of which is costs. This provides APA management with a major incentive to ensure costs are kept at an efficient level as significant personal rewards are directly linked to achieving financial targets.

The actual 2010/11 APA Group corporate costs were $c-in-c million.

These costs are then allocated to APTPPL via the allocation process described below.

8.4.1.2 *Consistent allocation methodology*

In the context of currently approved APA Group access arrangements (such as the access arrangements for the Victorian PTS, APT Allgas network, the Amadeus Gas Pipeline etc) it is in APA Group's interest to reduce operating costs, including corporate costs, wherever possible. APA Group has no incentive to increase corporate costs as to do so would increase costs to other APA Group regulated assets without the ability to reflect those costs in applicable reference tariffs a consequent reduction in margins. This causal nexus would not exist if different regulators used different allocation methodologies. The use of different allocation methodologies would reduce incentives to reduce corporate costs.

So long as the allocation methodology is consistent over time and across assets, the incentive mechanism is exerting a discipline on the amount of corporate costs incurred.

Furthermore, given the company-wide nature of the APA Group corporate costs and the asset footprint of the APA Group these costs are scrutinised, and will be scrutinised, by regulators other than the AER, notably the Economic regulation Authority of Western Australia, and will be scrutinised at each such regulatory reset.[85]

Consistency with APA Accounting Practice and Internal Cost Allocation Methodology

The allocation methodology now being put forward by APTPPL is the same methodology as used internally in APA Group in deriving budgets and internal

[85] APA currently has Access Arrangement on eight heavy regulation gas assets, including APT Allgas, where such costs would be scrutinised at resets.

accounts. This has been confirmed by Deloitte, the auditor. The audit report and supporting working papers demonstrate that APA Group's corporate costs are being recovered from the operating assets only once.

APA Group has consistently applied a revenue based cost allocation methodology, and this approach continues to be used to derive regulatory accounts required by relevant national gas and electricity laws. In some instances these regulatory accounts were or are provided to regulators.[86]

If different cost allocation methodologies were to be used on different assets in the future due to jurisdictional regulatory decisions this creates the potential for inadvertent under recovery or over recovery of these corporate costs across the whole APA Group.

Consistency with Allocation Methodology accepted by the AER and ACCC for the APA Group

It is noteworthy that consistency across the corporate group effectively requires the entire group to ultimately adhere to the most restrictive regulatory requirements among the group.

As APA Group owns electricity transmission assets, the cost allocation methodology must meet the most prescriptive requirements - those applicable to electricity transmission assets.

The revenue based methodology has been accepted by the AER and ACCC in relation to both electricity and gas assets owned, wholly or partially, by the APA Group. For example the revenue based methodology was put forward by APA in the Murraylink and Directlink cost allocation manuals, which are required by regulation, when these assets were wholly owned by APA Group. For example, the Directlink Manual[87] states:

> An annual cost allocation is undertaken for all shared costs arising from the provision of the above services by the APA Group. The allocation of these shared costs is made on the basis of revenue. As shown in Table 1 [of the Directlink manual], each business unit is allocated corporate overhead costs in proportion to their contribution to the APA Group's Total Revenue.
>
> Based on historical performance, Directlink believes revenue is an appropriate driver for allocating 'Corporate Overhead Costs' as corporate overheads are a necessary cost for the generation of revenue. Furthermore, a causal relationship exists between revenue generation and corporate overheads. Revenue is

[86] Murraylink and Directlink regulatory accounts using this allocation methodology have all been submitted to the relevant state or Commonwealth regulators in 2006, 2007 and 2008.

[87] 2008, APA group, *Directlink Manual* page 10.
http://www.aer.gov.au/content/index.phtml/itemId/718224

> therefore considered an appropriate driver for the allocation of 'Corporate Overhead Costs' to each of the APA Group's assets. It should be noted that in previous gas infrastructure regulatory decisions relating to APA gas assets the ACCC has accepted revenue as an appropriate allocator for corporate costs.

The AER approved these manuals.[88] The AER's consultant in this process noted[89] that the corporate cost allocation approach was consistent with National Electricity Rules cost allocation principles.

The revenue based allocation methodology is also the same corporate cost allocation methodology used by APA Group in regulatory decisions for such assets as the Moomba Sydney Pipeline and historically on the RBP. For example, the ACCC 2007 Draft Decision on the GasNet Access Arrangement states[90]:

> The APA Group's current approach is to allocate its corporate overheads on the basis of an asset's contribution to the APA Group's Total Revenue. In relation to its proposed revisions to the AA for the Roma to Brisbane pipeline (RBP) in 2006, the APA Group allocated 14 per cent of its indirect corporate costs to the RBP on the basis that the RBP contributed 14 per cent of the APA Group's revenue (in 2005). A similar approach was adopted by the APA Group for the Moomba to Sydney pipeline (MSP).

And further supports this by noting[91]

> The APA Group's annual ring fencing reports confirm that revenue shares are used as the basis for allocating corporate overheads.

The ACCC 2008 Final Decision on the GasNet Access Arrangement[92] states GasNet has made further confidential submissions on the issue of corporate costs. These submissions allocated corporate costs on the basis of revenue attributable to particular assets. In responding to these submissions in the Final Decision the ACCC did not raise any issues concerns with the corporate cost allocation methodology.

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[88] AER, 2008, *Final Decision Electricity Transmission Network Service Providers Cost Allocation Methodologies* August 2008 p10. http://www.aer.gov.au/content/index.phtml/itemId/718224

[89] 2008, McGrathNicol, *Review of Cost Allocation Methodology* Directlink 30 July 2008 page 11. http://www.aer.gov.au/content/index.phtml/itemId/718224

[90] ACCC, 2007, *Draft Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System*, p116

[91] ACCC, 2007, Draft Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System, 2007, p116

[92] ACCC, 2008, Final Decision, Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System, 2008, P80

This same revenue based cost allocation methodology has been applied in determining the share of corporate costs allocated to APTPPL for the purposes of this access arrangement.

Based on the revenue allocation methodology outlined above, the corporate costs allocated to APTPPL are summarised below.

The allocated corporate costs are based on the APA Group approved 2011-12 budget, adjusted by removing costs which are not related to functions provided to APTPPL. This includes costs associated with;

- Insurance, which is recovered separately;
- Corporate development including any future mergers, acquisitions, divestments or similar corporate projects;
- IT which is attributed to a specific business unit;
- Other commercial services attributed to a specific business unit; and
- APTPPL IT costs – which are added in as a separate item.

The revenue allocator used is the budgeted revenue of APTPPL as a percentage of total APA revenue. For 2010/11, this allocator is 6.9%.

The actual APA Group corporate costs allocated to APTPPL for 2009/10 using this methodology are $3.4 million. As a reasonableness check, APTPPL notes that direct application of the revenue allocator to all APA Group corporate overhead costs would have resulted in an allocated amount of $4.2 million.

8.4.1.3 *Corporate cost benchmarking*

APTPPL benefits from the centralisation of these functions - the cost to APTPPL would be much greater if it had to source each of these functions for its exclusive use.

In order to confirm and quantify the benefits of using a centralised corporate function instead of duplicating these functions as stand alone functions for each of APA Group's assets, APA Group has commissioned a report from KPMG which examines this issue and estimates the reasonable level of non capital corporate costs for an asset with the characteristics of APTPPL.

This KPMG report is attached at Attachment 8.6. This report effectively derives a corporate cost benchmark as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

The KPMG report undertakes cost modelling of the non capital corporate costs for an asset with the characteristics of the RBP. This modelling identifies corporate functions that would be required by an asset with the characteristics of the RBP and then models costs for these corporate functions. This modelling is based on a series of empirical cost benchmarks. The cost modelling is explicitly undertaken to meet the requirements of Rule 91.

The KPMG report concludes that an expected range of Non Capital corporate costs (in $2011) for an asset with the characteristics of the RBP is in the order of $4.6 million per annum.[93] APTPPL submits that this midpoint demonstrates that its submitted corporate cost of $3.4 million for 2011 demonstrates significant synergies associated with the centralisation of corporate functions. APTPPL submits that the KPMG report strongly supports APTPPL's position that its forecast corporate costs meet the requirements of Rule 91.

In considering the KPMG report the AER should recognise that the cost categorisations used by APTPPL and KPMG may differ due to APA internal cost centre definitions and KPMG cost benchmarks not being aligned. However the fact that the total amount of corporate costs is materially below KPMG's benchmark indicates that the APTPPL corporate costs are reasonable costs when compared with a benchmark prudent service provider, acting efficiently, in accordance with accepted and good industry practice.

APTPPL submits that the full range of corporate overhead costs submitted by APTPPL in its forecast of Non Capital Costs for the forthcoming Access Arrangement Period meet the prudent service provider test under Rule 91. That is, these costs are such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

8.4.2 Consistency with the National Gas Objective and the Legitimate Interests of Service Providers

APTPPL believes that ensuring that corporate costs are recovered once, but only once, is in the interests of both the Service provider and the Users. To recommend a cost allocation methodology that increases the potential for the over-recovery or under-recovery of costs is not in the interests of either the Service Provider or the Users, and as such is not consistent with the national gas objective.

Furthermore Section 24(2)(a) of the National Gas Law requires that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services. To recommend a cost allocation methodology that increases the potential for the under-recovery of costs is not consistent with the recovery of efficient costs.

[93] KPMG, 2010, Corporate Cost Benchmarking , page 1. Attachment 8.6.

Similarly, recommending a cost allocation methodology which differs to that used in other regulatory proceedings has the potential to distort investment decisions. Such an approach may create inappropriate incentives to invest in some infrastructure assets in preference to others, depending on the treatment of costs in the relevant regulatory decisions.

Overall, the APA Group seeks to consistently apply a single cost allocation methodology across all of its operating businesses and Access Arrangements. To the extent that this consistent application is not approved across the range of regulatory processes, this raises the potential for either inadvertent under-recovery or over-recovery of corporate costs. APA Group has consistently used the revenue based allocation internally and in submissions to the ACCC, AER and Economic Regulation Authority.

8.5 Summary: forecast operating expenditure

Table 8.10: Total forecast expenditure in the access arrangement period

$000 (2011/12)	2012/13	2013/14	2014/15	2015/16	2016/17
Labour	5,819	6,002	6,190	6,483	7,008
Contractors – O&M	878	935	989	1,014	1,019
Other Operating Costs	1,137	1,211	1,282	1,394	1,320
Operating Costs	7,834	8,148	8,461	8,891	9,347
Asset Licences and Insurance	634	634	634	634	634
Regulatory Costs	-	-	-	-	767
Debt Raising Costs	248	241	233	225	217
Corporate Costs	3,732	3,851	3,990	4,277	4,564
Total Operating Expenditure	12,447	12,874	13,318	14,027	15,528

9 Tariffs

In this section the building blocks are assembled to form the total revenue requirement, and the process outlined by which that total revenue requirement is allocated among pipeline services and allocated over revenue drivers to derive the Reference Tariff.

9.1 Total revenue requirement

Rule 76 outlines the procedure for developing the total revenue requirement:

> 76 Total revenue
>
> Total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:
>
> (a) a return on the projected capital base for the year (See Divisions 4 and 5); and
>
> (b) depreciation on the projected capital base for the year (See Division 6); and
>
> (c) if applicable – the estimated cost of corporate income tax for the year; and
>
> (d) increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency (See Division 9); and
>
> (e) a forecast of operating expenditure for the year (See Division 7).

The total revenue requirement is summarised below:

Table 9.1: Total revenue requirement

$m (2012 real)	2012/13	2013/14	2014/15	2015/16	2016/17
Return on capital	40.15	39.02	37.85	36.48	35.18
Regulatory depreciation	5.33	6.46	7.70	7.61	6.95
Tax allowance	2.02	3.76	3.79	3.73	3.60
Incentive mechanisms	0	0	0	0	0
Operating expenditure	12.45	12.87	13.32	14.03	15.53
Total revenue requirement	59.95	62.11	62.66	61.85	61.26

9.2 Services

The previous AA applied to the Existing Capacity of the RBP, that being the capacity of the pipeline as configured at 01 January 2006, or 203 TJ/day. The Extensions and Expansions policy also made it clear that if APTPPL extended or expanded the pipeline, the services provided by the extension or expansion would be provided as a Negotiated Service at a negotiated tariff.[94]

Since the previous AA became effective, APTPPL has undertaken extension (the Lytton lateral) and expansion (RBP8) of the RBP, and has provided access to the services provided by the extensions and expansions as Negotiated Services at negotiated tariffs.

For the purpose of developing the Reference Tariff, then, it is necessary to allocate the total revenue requirement between the Reference and Negotiated services, as described below.

9.3 Revenue and Cost Allocation Process

Rule 93 provides a process under which costs are allocated among services, and then the total revenue is allocated in proportion to the costs allocated:

> 93 Allocation of total revenue and costs
>
> (1) Total revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services.

[94] RBP AA 2007-1012, clauses 7.1(b) and 7.2(b).

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

(a) costs directly attributable to reference services are to be allocated to those services; and

(b) costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and

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

Once the total revenue requirement attributable to the provision of Reference Services is determined through this cost allocation process, tariffs to recover the portion of total revenue referable to that reference service are developed according to the provisions of Rule 95.

9.3.1 Approach

In order to allocated costs between the Reference and Negotiated services, APTPPL has adopted a with/without approach. In this approach, the total revenue requirement of the RBP includes all assets included as part of the Capital Base and all associated return on and of capital, all operating costs, and the tax impact as outlined above.

APTPPL has tracked the capital costs associated with the Lytton later and RBP8 projects. These are shown as separate asset classes in the AER's Asset Base Roll Forward Model (ABRFM) and Post Tax Revenue Model (PTRM).

To determine the costs attributable to these projects, APTPPL has excised this capital expenditure from the ABRFM, and removed the associated operating costs (including a share of common and overhead costs) from the PTRM opex forecast.

The PTRM is then re-run, excluding the costs associated with the extensions and expansions, to determine the total revenue requirement attributable to the Reference Service. Regulatory depreciation and the tax allowance are calculated by the PTRM.

9.3.2 Directly attributable costs

The costs directly attributable to the Reference Service are assessed as the cost of providing pipeline services prior to the introduction of Negotiated Services. It includes the return on and of capital associated with the RBP required to provide the Reference Service (that is, the pipeline as configured as at 01 January 2006 with

any necessary Stay In Business capital) and the operating costs associated with the pipeline as so configured.

The costs directly attributable to the Negotiated Services include the return on and of capital associated with the investment required to provide those services. These have been separately identified as excised from the calculation of Reference Tariffs through the ABRFM and PTRM as discussed above.

9.3.3 Other costs

The Lytton lateral and RBP8 being relatively new investments (RBP8 is not yet in service at the time of writing), APTPPL does not have a history of actual operating costs related to these services. In estimating the operating costs attributable to these services, APTPPL has relied on its engineering experience to estimate the direct operating costs associated with these pipelines, based on size and pressure, terrain, construction methodology, etc.

To this APTPPL has added an estimate of the associated common and corporate operating costs that could be reasonably allocated to these services. This total is reflected in the business cases provided to the AER in respect of these projects.

9.4 Prudent Discounts

Rule 96 allows for all or part of the revenue shortfall associated with providing prudent discounts to be recovered through the Reference Tariff:

> 96 Prudent discounts
>
> (1) Despite the other provisions of this Division, the AER may, on application by a service provider, approve a discount for a particular user or prospective user or a particular class of users or prospective users.
>
> (2) The AER may only approve a discount under this rule if satisfied that:
>
> (a) the discount is necessary to:
>
> (i) respond to competition from other providers of pipeline services or other sources of energy; or
>
> (ii) maintain efficient use of the pipeline; and
>
> (b) the provision of the discount is likely to lead to reference or equivalent tariffs lower than they would otherwise have been.
>
> Note:

Even though a user's incremental load is retained at a discounted price, overall tariffs may be lower because of the user's contribution to fixed costs.

(3) If the AER approves a discount under this rule, the AER may also approve allocation of the cost, or part of the cost, of providing the discount to the costs of providing a reference or other service in one or more future *access arrangement periods*.

(4) In this rule:

equivalent tariff means the tariff that is likely to have been set for a service that is not a reference service if the service had been a reference service.

APTPPL makes no application for the AER to approve a Prudent Discount at this time.

9.5 Surcharges

Rule 83 outlines a process under which the Service Provider can apply to the AER to approve a surcharge designed to recover costs associated with non-conforming capital expenditure.

APTPPL has made no non-conforming capital expenditure and therefore does not request the AER's approval to levy a surcharge.

9.6 Reference Tariff Adjustment Mechanism

APTPPL proposes to revise its reference tariff adjustment mechanism included in the previous access arrangement. The need to do this arises largely due to changes in relevant provisions in the Rules compared to the former National Gas Code.

Rule 97 provides that the reference tariff may vary during the access arrangement period pursuant to a number of methods as set out in that Rule. APTPPL has included two reference tariff adjustment mechanisms in its access arrangement:

- An annual reference tariff adjustment formula mechanism – to apply on 1 July 2013 and on each subsequent 1 July which adjusts the reference tariff for changes in CPI; and

- A cost pass-through reference tariff adjustment mechanism – under which APTPPL may seek to vary the reference tariff as a result of a cost pass-through event.

This is similar to the previous access arrangement where the reference tariff was adjusted by CPI and by new legislative or regulatory obligations.

In deciding whether a particular reference tariff adjustment mechanism is appropriate, the AER must have regard to:[95]

- the need for efficient tariff structures;
- the possible effects of the tariff variation mechanism on administrative costs of the AER, the service provider, and users and potential users;
- the regulatory arrangements applicable in the previous access arrangement; and
- the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

APTPPL has modelled its Reference Tariff Adjustment Mechanism on that recently approved by the AER for the Amadeus Gas Pipeline (AGP). Variations from the mechanism approved by the AER are noted in the discussion below.

APTPPL submits that its proposed reference tariff variation mechanism is consistent with the requirements of Rule 97.

9.6.1 Annual reference tariff adjustment formula mechanism

Rule 97(1)(b) states that a reference tariff adjustment mechanism can provide for the variation of a reference tariff in accordance with a formula set out in the access arrangement.

APTPPL's earlier access arrangement included an annual tariff adjustment formula in its tariff adjustment mechanism to vary all prices by CPI and an X factor. The X factor smooths required tariff changes over the access arrangement period. APTPPL proposes to retain this annual tariff adjustment formula in the coming access arrangement period. APTPPL's proposed X factors are discussed in Section 9.7 below.

The only variation to this formula from that in the previous access arrangement period is the inclusion of a definition of 'n', which is taken from the AER approved AGP access arrangement.

APTPPL submits that its proposed annual reference tariff adjustment formula mechanism is consistent with Rule 97(3) as it:

- ensures that tariffs move with changes in CPI[96];
- is readily verifiable by external parties, including users and prospective users, thereby reducing compliance costs[97];

[95] Rule 97(3)
[96] Rule 97(3)(a)

- is consistent with the previous APTPPL access arrangement, in providing for the annual adjustment of the reference tariff in accordance with movements in CPI[98]; and

- is consistent with recent AER decisions for access arrangements applying to similar services, for example in relation to the AGP[99].

9.6.2 Cost pass-through reference tariff adjustment mechanism

Rule 97(1)(c) specifically allows a service provider to include in its access arrangement a reference tariff adjustment mechanism that allows the reference tariff to vary as a result of a cost pass-through for a defined event. APTPPL proposes to include a cost pass-through reference tariff adjustment mechanism in the access arrangement to ensure APTPPL can reflect incremental costs resulting from material unforeseen or uncontrollable events in the reference tariff.

APTPPL's previous access arrangement included a limited cost pass-through event mechanism, and relied on the process for approving events set out in the Code. The transfer to the Rules means that this mechanism must be set out in the access arrangement in more detail. APTPPL has based its cost pass-through reference tariff adjustment mechanism in large part on that approved by the AER for the AGP.

APTPPL has included the following defined cost pass-through events in its proposed access arrangement:

- An insurance cap event;

- An insurer credit risk event;

- A natural disaster event;

- A regulatory change event;

- A service standard event;

- A tax change event; and

- A terrorism event.

All of these events were approved by the AER in respect of the AGP. The only variations to the definitions approved by the AER proposed by APTPPL are:

[97] Rule 97(3)(b)
[98] Rule 97(3)(c)
[99] Rule 97(3)(d)

- Insurance Cap Event – refining the exclusions to the Insurance Cap Event to Service Provider's Wilful Misconduct and Gross Negligence, in line with service provider liability in the access arrangement. This approach aligns with the access arrangement and limits uncertainty as these terms are defined in the access arrangement. The reference to Wilful Misconduct eliminates the need to refer to liability and damages arising from actions or conduct expected or intended by the Service Provider; and

- Tax Change Event – inclusion of a definition for *Tax* and *Relevant Tax* for the purpose of the definition. The definitions are aligned with those in the National Electricity Rules and reduce uncertainty as to the scope of this cost pass through event.

All other definitions are identical to those previously approved by the AER in respect of the AGP, including the definition of the materiality threshold.

The only other variation to the cost pass-through adjustment mechanism included in the AGP access arrangement is in the opening paragraph to section 4.5.2. APTPPL has included scope for a cost pass through event approval to relate to costs that are reasonable expected to be incurred, as per the excerpt from the proposed access arrangement below:

> Subject to the approval of the AER under the National Gas Rules, Reference Tariffs may be varied after one or more Cost Pass-through Event/s occurs, in which each individual event materially increases or materially decreases, *or is reasonably expected to materially increase or decrease,* the cost of providing the Reference Service. Any such variation will take effect from the next 1 July.

APTPPL considers that inclusion of scope for the AER to approve reasonably expected future costs better meets the requirements of Rule 97(3)(a) as it provides for more efficient tariff structures in some specific instances.

An example where future costs may be approved for pass through by the AER relates to the initial phase of the carbon pricing scheme, which will impose a fixed price for the first three years of the regime. In this period, APTPPL's carbon costs can be readily estimated as the cost of permits is known, and the level of emissions can be readily forecast based on emissions. Uncertainty over the imposition of the regime, however, means that APTPPL has not included the costs in its forecast operating expenditure for the period.

In this case, it would be preferable for the AER to approve a pass-through amount for costs associated with the coming regulatory year, therefore aligning APTPPL's costs with revenue, and ensuring the incentive effect of the carbon price is passed through to users in real time. This approach would also ensure that APTPPL could recover the costs of a carbon price in the final year of the access arrangement. There is currently considerable uncertainty as to how costs can be recovered by

service providers in the final year of the access arrangement where tariff adjustments are limited to each 1 July within the period.

APTPPL also notes that this approach is consistent with the notification process included in the AGP access arrangement and reproduced in the RBP access arrangement, which provides for notification of the costs of a cost pass-through event when those costs are known, or able to be estimated to a reasonable extent. This drafting suggests that cost pass through events may relate to future costs.

APTPPL submits that its proposed cost pass-through reference tariff adjustment mechanism is consistent with Rule 97(3) as it:

- Ensures that the tariff reflects the efficient costs of providing the reference service by providing a mechanism to allow unforeseen and uncontrollable costs to be reflected in the reference tariff[100];
- Is simple to understand and not burdened by legal jargon making it easier to comprehend and apply, thereby reducing compliance costs[101];
- Is consistent with the earlier access arrangement, in providing for the pass through of costs associated with new obligations[102]; and
- Is consistent with recent AER decisions for similar services, for example in relation to the AGP [103].

9.6.3 Notification and approval of cost pass through events

APTPPL had adopted the process for notification and approval of cost pass-through events approved by the AER in respect of the AGP without change.

This process requires APTPPL to notify the AER of a cost pass-through event within 90 business days of the cost pass-through event occurring, whether the cost pass-through event would lead to an increase or decrease in reference tariffs. When the costs associated with an event are known, or able to be estimated to a reasonable extent, those costs must be notified to the AER. The AER must advise of its decision in respect of a cost pass-through event within 90 days, with scope for extension of this time. Approved cost pass-through amounts are then reflected in the tariff adjustment notice in respect of the following 1 July.

[100] Rule 97(3)(a)
[101] Rule 97(3)(b)
[102] Rule 97(3)(c)
[103] Rule 97(3)(d)

9.6.4 Annual Reference Tariff Adjustment Process

A key change in APTPPL's access arrangement is in the tariff adjustment process. The former National Gas Code included a process for assessing tariff adjustments that is not reproduced in the Rules.[104] It is therefore necessary to include a tariff adjustment process in the RBP access arrangement. APTPPL has adopted the tariff adjustment process approved by the AER in respect of the AGP access arrangement.

The tariff adjustment process provides for annual adjustment of tariffs each 1 July in respect of both the annual reference tariff adjustment formula mechanism and the cost pass-through reference tariff adjustment mechanism. APTPPL must provide the AER with a notification of proposed tariffs to apply from the following 1 July 50 business days before that 1 July. While APTPPL notes that this timing does not allow it to include in that notification finalised tariffs that take account of the March CPI value, this process does allow the AER to review the tariff variation mechanism and calculation, with the March CPI value able to be inserted into the formula once it has been released by the Australian Bureau of Statistics. APTPPL considers this process gives the AER adequate oversight and powers of approval over variations to the reference tariff.

The only variation to the process approved by the AER relates to the treatment of material errors or deficiencies in past tariff variations. APTPPL considers that any error in a past tariff variation must be verified – it is insufficient for a change to be only apparent. APTPPL has therefore clarified the AER's powers to take account of a past error to actual errors.

APTPPL submits that its proposed tariff adjustment process is consistent with Rules 97(3) and (4) as it:

- Ensures that the tariff reflects the efficient costs of providing the reference service by providing a mechanism to allow tariffs to be varied in accordance with the Reference Tariff Adjustment Mechanism[105];
- Limits the administrative costs of the APTPPL, the AER and users by provided for annual tariff variations[106];
- Is consistent with recent AER decisions for similar services, for example in relation to the AGP [107];and
- Provides the AER with adequate oversight and powers of approval over the variation of the reference tariff[108].

[104] National Gas Code sections 8.3 -8.3H
[105] Rule 97(3)(a)
[106] Rule 97(3)(b)
[107] Rule 97(3)(d)

9.6.5 Reference Tariff to apply after 30 June 2017

In the event that the revisions commencement date is later than 30 June 2017, APTPPL proposes that the tariff in effect at 30 June 2017 continue to apply to the provision of the firm Service between 30 June 2017 and that later revisions commencement date. This approach is consistent with Rule 92(3).

If the reference service under the following access arrangement is different to those in the current access arrangement period, the applicable reference tariff and terms for an existing service being supplied to a User are those as at the revisions commencement date.

9.7 Price path

AS discussed above, APTPPL proposes to adopt a CPI-X price adjustment mechanism to adjust Reference Tariffs. The X factor will apply equally to the Capacity and Throughput charges.

APTPPL proposes the following X factors for the 2012-17 AA period, each to be used to adjust Reference Tariffs effective on the first day of the relevant year:[109]

Table 9.2: Proposed X factors

Effective 01 July	2012/13	2013/14	2014/15	2015/16	2016/17
Proposed X Factor	-17.8%	-13.0%	-13.0%	-13.0%	-13.0%

9.8 Revenue equalisation

Rule 92(2) requires the present value of the revenue derived from Reference Tariffs to be equal to the present value of the total revenue requirement attributable to Reference Services:

> 92 Revenue equalisation
>
> (2) The reference tariff variation mechanism must be designed to equalise (in terms of present values):
>
> (a) forecast revenue from reference services over the access arrangement period; and

[108] Rule 97(4)

[109] It should be noted that these AA revisions are scheduled to become effective on 13 April 2010. APTPPL proposes that the existing Reference Tariffs remain unchanged at that date.

(b) the portion of total revenue allocated to reference services for the access arrangement period.

As developed above, the total revenue requirement attributable to the Reference Service is:

Table 9.3: Total Reference Service revenue requirement

$m (2012 real)	2012/13	2013/14	2014/15	2015/16	2016/17
Reference Service revenue requirement	53.06	55.28	55.89	55.14	54.61

The present value of this required revenue, discounted at the proposed real WACC of 6.84%, is $225.50m.

The forecast Reference Service revenues reflecting the load and demand forecast developed in Section 3 are:

Table 9.4: Forecast revenue

$m (2012 real)	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast Reference Service revenue	43.67	49.37	55.79	63.09	65.67

The present value of this forecast revenue, discounted at the proposed real WACC of 6.84%, is $225.50m.

10 Queuing

The NGR requires that any access arrangement for a transmission pipeline must contain queuing requirements.[110] Rule 103 contains the following relevant provisions in relation to queuing requirements:

> (3) Queuing requirements must establish a process or mechanism (or both) for establishing an order of priority between prospective users of spare or developable capacity (or both) in which all prospective users (whether associates or, or unrelated to, the service provider) are treated on a fair and equal basis.
>
> (4) Queuing requirements might (for example) provide that the order of priority is to be determined:
>
> (a) on a first-come-first served basis; or
>
> (b) on the basis of a publicly notified auction in which all prospective users of the relevant spare capacity or developable capacity are able to participate.
>
> (5) Queuing requirements must be sufficiently detailed to enable prospective users:
>
> (a) to understand the basis on which an order of priority between them has been, or will be, determined; and
>
> (b) if an order of priority has been determined – to determine the prospective user's position in the queue.

10.1 Current Queuing Arrangements on the RBP

Under the current access arrangement for the RBP, where there is insufficient capacity to satisfy a request from a user for capacity (either in full or in part), a queue is formed.[111]

The current access arrangement makes provision for two separate queues: one for existing capacity and one for developable capacity. APTPPL notes that the AER required the provision for two separate queues as a condition of approving the current RBP Access Arrangement.[112]

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110 NGR Part 10 Division 2 103(1)(a).

111 Current RBP Access Arrangement, section 6.1.

112 ACCC, Final Approval – Roma to Brisbane Pipeline – revised access arrangement, 28 March 2007, p. 13.

Existing capacity on the RBP is currently fully contracted. As a consequence, there is currently a queue in existence for existing capacity. There is also currently a queue in existence for developable capacity.

10.1.1 Existing capacity

The current queuing requirements for existing capacity reflect a 'first-come-first-served' approach, and are set out in sections 6.3 and 6.4 of the current access arrangement. Key features of the current approach include:

- Priority is in order of the date at which prospective users applied to join the queue;
- The exception is where a Request is for less than the Reference Tariff, in which case a later Request for capacity at the Reference Tariff will be given priority in the queue over this Request;
- When existing capacity becomes available, it is progressively offered to each prospective user in the queue, in order of priority; and
- The prospective user then has 30 days to enter into a Transportation Agreement, failing which the Request will lapse or lose priority.

10.1.2 Developable capacity

The current queuing requirements for developable capacity are set out in sections 6.5, 6.6 and 6.7 of the current access arrangement, and also reflect a 'first-come-first-served' approach. Key features of the current approach include:

- Priority is in order of the date at which prospective users applied to join the queue;
- The exception is if the expansion or extension is offered as part of the Reference Service. In this case a Request has priority over another Request which is for less than the Reference Tariff;
- If investigations are required, APTPPL will (on request) provide prospective users with a general non-binding indication of the range of tariffs which may be applicable in relation to any expansion;
- APTPPL is obliged to undertake investigations into developable capacity if one or more prospective users agrees to bear the cost of such investigations;
- Where a prospective user declines to meet the cost of investigations, its Request will have lower priority in the queue than Requests from users who have agreed to bear the cost;

- Where investigations identify that investment is required, APTPPL will advise each of the Prospective Users in the developable capacity queue of its plans and terms and conditions on which new capacity will be available;

- Prior to development, the capacity will be progressively offered to each prospective user in the queue, in order of priority; and

- A prospective user has 30 days to enter into a transportation agreement (conditional if necessary on APTPPL entering into transportation agreements with other Prospective Users), failing which the request will lapse or lose priority.

10.2 Problems experienced with the current queuing requirements

APTPPL's experience with the queuing requirements over the current access arrangement period has highlighted a number of issues with the efficiency of the arrangements, particularly in relation to the queue for existing capacity.

Firstly, APTPPL has found that when existing capacity does become available, there are sometimes users close to the front of the queue who do not genuinely want that capacity. In these circumstances, the first-come-first-served approach can become time consuming, as the capacity needs to be offered to each prospective user in the queue sequentially, even where some users do not genuinely want that capacity. This problem is exacerbated since the queue is costless to join. This increases the incentives for prospective users to join the queue, however speculative their requirement for capacity, and results in excessive 'queue sitting'.

This also demonstrates a genuine concern over capacity hoarding, whereby non-intending users can occupy positions on the queue as a strategy to discourage competitors from entering the market or planning to expand their positions in the market. This is clearly not an efficient outcome.

More fundamentally, a first-come-first-served approach has the potential to result in inefficient outcomes, where prospective users higher in the queue want to take capacity later and/or for shorter periods than those further down in the queue. APTPPL's experience has been that prospective users tend to align their queue requirements to the lead time for particular projects or expected needs. This means that prospective users higher in the queue who want capacity later can contract for that capacity and block its allocation to other prospective users who would be willing to take that capacity as soon as it becomes available. The current queuing arrangements also do not allow the flexibility to allow higher value projects to take precedence over lower value projects, when it is not possible to meet the needs of both.

APTPPL has commissioned NERA Economic Consulting to examine the implications for economic efficiency of the first-come-first-served approach to allocating capacity. NERA's report is included as Attachment 10.1 to this submission. NERA concludes that for existing capacity, queuing requirements

based on a first-come-first-served approach have the potential to result in the economically inefficient allocation of existing capacity, given the particular circumstances of the RBP.

In the case of developable capacity, APTPPL's experience under the current queuing requirements has been that it has been difficult to co-ordinate Requests for developable capacity, due to the sequential nature of the discussions held under the first-come-first-served approach. APTPPL also has concerns about the ability of the current arrangements to facilitate the timely expansion of capacity.

10.3 Proposed queuing arrangements – existing capacity

Given the difficulties which have been experienced with the queuing requirements in relation to existing capacity, APTPPL is proposing to change the queuing requirement for existing capacity in the forthcoming access arrangement period.

The Rules do not constrain the approach that can be taken by the service provider in relation to the particular queuing requirements adopted for the pipeline. Provided that the queuing requirements 'establish a process or mechanism (or both) for establishing an order or priority between prospective users' in a manner which ensures that all prospective users 'are treated on a fair and equal basis', then the requirements comply with Rule 103.

APTPPL further notes that Rule 103 explicitly provides that queuing requirements may be in the form of:

> 'a publicly notified auction in which all prospective users of the relevant existing capacity or developable capacity are able to participate.'

As noted above, APTPPL commissioned NERA to advise on alternative queuing requirements. In particular APTPPL asked NERA whether the adoption of a publicly notified auction for existing capacity would be likely to result in a more efficient allocation of capacity than under the current first-come-first-served approach. NERA's conclusion is that an auction approach to allocating existing capacity is more likely to result in an economically efficient allocation. Allocating capacity on the basis of an auction allows users who are willing to hold the capacity earlier and/or for longer to be ranked ahead of those users whose request for capacity is for a shorter term, or is further in the future.

The adoption of an auction as a means of allocating existing capacity also provides a more timely means of determining the allocation of existing capacity.

APTPPL therefore proposes to change its queuing policy for the forthcoming access arrangement period from a first-come-first-served approach to a publicly notified auction. The details of the proposed mechanism are set out in the proposed revisions to the Access Arrangement which is being provided to the AER alongside this submission. However the key features of the proposed approach are:

- APTPPL will accept Expressions of Interest for the allocation of Existing Capacity. These Expressions of Interest will not be associated with any ranking or priority in access to this capacity;

- APTPPL will notify all Users and Potential Users who have filed Expressions of Interest, and may advise other interested parties that an auction of existing capacity is planned to take place. APTPPL will also advertise the auction in a national newspaper;

- Prospective users are required to submit bids which specify demand, volumes, commencement and end dates, and receipt and delivery points;

- Bids may be for the Reference Service at the Reference Tariff, or for a Negotiated Service for which the user proposes a negotiated tariff;

- Bidders will also be required to meet prudential requirements;

- Bids are irrevocable, and submitted in the form of an executable contract;

- Once the period allowed for the auction has expired, bids will be ranked by APTPPL on a Net Present Value (NPV) basis, with Requests which have a higher NPV ranked ahead of requests with a lower NPV; and

- 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.

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

APTPPL considers that the adoption of a public auction for existing capacity will better meet the National Gas Objective. In particular it is expected to promote the efficient use of natural gas services, by ensuring that existing capacity is allocated to those users who value it most.

An auction approach is also expected to allocate capacity in a way which is in the long term interests of consumers with respect to price, reliability and security of supply. The ability for users to submit 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 the Reference Service. Moreover, for Negotiated Services the tariff paid for the capacity will reflect that determined by the auction, and is not set by APTPPL. Prospective users therefore do not face the threat of the exercise of monopoly power in relation to determining the tariff.

APTPPL notes further that the access arrangement for the RBP allows users to trade the capacity they have under contract. This is in accordance with Rule 105. In particular, for the new access arrangement period the capacity trading requirements in the access arrangement will allow users to transfer or assign all or part of their

contracted capacity, without the prior consent of APTPPL. As a consequence, where the allocation of capacity under the queuing requirements does not result in the capacity being allocated to the user that values it the most, it would be possible for users to re-allocate capacity by trading the contracted capacity between themselves. This subsequent trading of capacity would then determine the ultimate price paid for that capacity, based on its market value.

10.4 Proposed queuing arrangements – developable capacity

APTPPL also proposes to adopt a public auction approach in relation to the queuing requirements for developable capacity. APTPPL considers that this change in the queuing approach will better facilitate co-ordination 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 goal of the developable capacity process is quite different from that related to Existing Capacity. For Existing Capacity, there is a finite quantity of a defined commodity available for auction; for developable capacity, the amount of capacity to be developed relies heavily on the ability to coordinate users in order to achieve economies of scale in that capacity development.

The details of the proposed mechanism are set out in the proposed revisions to the Access Arrangement which is being provided to the AER alongside this submission. The key features of the queuing requirements for developable capacity proposed for the next access arrangement period are:

- APTPPL will accept Registrations of Interest in developable capacity at any time. Such a Registration of Interest does not imply priority of access to any developable capacity. This Register provides a signal to APTPPL as to when there may be sufficient potential interest to justify running the more formal expression of interest process discussed below;

- Where APTPPL considers that there is likely to be sufficient interest in developable capacity it will request from users on the Register of Interest, and issue a public notice requesting, (non-binding) expressions of interest in such capacity, including commencement, term, volumes, and receipt and delivery points; and

- No priority of access to the developable capacity will be established by filing such an expression of interest.

Following receipt of expressions of interest, APTPPL will conduct 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.

Once these investigations are completed, assuming that APTPPL has identified a project which meets the above requirements, the developable capacity associated with that project will be offered to prospective users on the following basis:

- Where APTPPL has determined on the basis of the investigations undertaken and the registrations of interest for Services that have been lodged that Developable Capacity may be made available, it may conduct negotiations with Prospective Users with respect to that Developable Capacity or hold an auction to determine the allocation of that Capacity in the event that the investment in the Developable Capacity proceeds

- Where APTPPL has determined that it will hold an auction for Developable Capacity, it will advertise the auction period, and provide an indication of potential tariffs that are likely to apply to the new capacity:[113] The indicative tariff may be presented as a range, conditional on APTPPL entering into agreements covering different quantities of total capacity;

- Participation in the auction will be open to any prospective users, provided that they can satisfy the terms set out in the bidding documents (which will include such factors as meeting minimum prudential requirements and demonstrating that they expect to have access to a supply of gas);

- Responses to the auction will be required to be in the form of an executable contract, including a proposed negotiated tariff.[114] Responses will therefore include the period for which the capacity is sought, the quantity sought and any variations required to the standard terms and conditions;

- Following the closure of the auction period, APTPPL will confirm contracts for the developable capacity from those parties who have submitted bids;

- If the total capacity the bidders agree to accept is more than the total feasible expansion size, capacity will be allocated between prospective users on the basis of the NPV of their bids, taking into account all of the terms of the offers and commercial factors including risk, from highest to lowest; and

- If the total capacity the bidders agree to accept is less than that assumed by APTPPL in designing the expansion and setting the indicative tariffs, then APTPPL will either proceed with those contracts, or enter into bilateral negotiations with those prospective users who have submitted bids with the aim of agreeing contracts for a smaller sized expansion.

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[113] Under the extensions and expansions policy, APTPPL will elect whether access to incremental services provided using an expansion of capacity will be offered as part of the Reference Service at the Reference Tariff, or as a Negotiated Service at a negotiated tariff (Proposed Access Arrangement, 7.2(b)).

[114] Or the Reference Tariff, where APTPPL elects to include the expansion as part of its Reference Service, and the user is seeking the Reference Service.

The above form of queuing requirement is a mechanism (ie, a form of auction) which will determine how users can gain access to developable capacity.

APTPPL believes that an approach to allocating developable capacity on the basis of an expression of interest process followed by an auction (as outlined above) is likely to result in more timely and effective means of co-ordinating capacity expansions than a first-come-first-served approach. This is because it imposes time-bounded periods for both expressions of interest and subsequent bids to be submitted and provides for concurrent negotiations between parties.

This 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 it better meets the National Gas Objective. In particular it will result in more efficient investment in natural gas services and is in the long term interests of consumers in relation to the price charged for the service and for reliability and security of supply. These advantages are also highlighted in the NERA report.

APTPPL considers that its proposed queuing policy:

- Complies with the requirements of Rule 103;
- Provides for a fair and efficient allocation of spare Existing and Developable Capacity; and
- Promotes the National Gas Objective in that it promotes efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

A Description of general changes to the access arrangement

Section	Change	Reason for change
General	Clause cross references and capitalisation of defined terms	Update of appropriate clause cross references for internal document consistency, as well as capitalisation of defined terms. These changes are not tracked.
General	References to APTPPL in access arrangement replaced with references to Service Provider	Alignment with standard form for APA Group access arrangements
General	Reference to Terms and Conditions, in place of General Terms and Conditions	Alignment with standard form for APA Group access arrangements
General	Reference to the Firm Service, in place of Reference Service	Alignment with standard form for APA Group access arrangements
1.1	Replacement of references to Gas Code with relevant National Gas Law and Rules references	Move from Gas Code to National Gas Law and Rules
1.2	References to APTPPL in access arrangement replaced with references to Service Provider	Alignment with standard form for APA Group access arrangements
1.3	Change reference to July 2012 on scope of covered pipeline. References to Lytton Lateral Pipeline included.	Update the access arrangement for the current period Lytton Lateral covered since last access arrangement with access provided as a Negotiated Service as per the extensions and expansion policy in place at the time.
1.4	Update reference to extensions and expansions	Move from Gas Code to National Gas Law and Rules
1.5	Replacement of references to Gas Code terms with relevant	Move from Gas Code to National Gas Law and Rules

	National Gas Law and Rules references	
1.6	Update for revisions submission and commencement date for the new access arrangement period	Revisions submission and commencement dates are discussed in section 1.4.3 New definition for Revisions Submission Date included for clarity
1.7	Change reference to Definitions and Interpretation	Alignment with standard form for APA Group access arrangements
1.8	Structure/contents page of AA updated	Alignment with other AA changes
2.1	Reference to Firm Service, in place of Reference Service	Alignment with standard form for APA Group access arrangements
2.1.1	Text moved from former clause 2.1.2 and revised Access arrangement terms and conditions apply only to the Firm Service	Alignment with standard form for APA Group access arrangements Move from Gas Code to National Gas Law and Rules, as well as recognition of the different arrangements that can be supported as a negotiated service.
2.1.2	Update cross referencing and terms in document	Move from Gas Code to National Gas Law and Rules
2.2.1	Reference to Firm Service, in place of generic “Reference Service” Reference to Authorised Overruns in place of Overrun facility Inclusion revised description of the Firm Service, incorporating some of deleted paragraphs from clause 2.2.2 Inclusion of paragraph on arrangements for the Brisbane hub	Alignment with provisions in APA Group’s standard form term and conditions for a Firm Service and Authorised Overruns Specific arrangements required as a result of the introduction of the STTM in Queensland
2.2.2	References to Firm MDQ Changes to MDQ and MHQ arrangements, including transferring some paragraphs to clause 2.2.2	Alignment with provisions in APA Group’s standard form term and conditions for a Firm Service

2.2.3	Inclusion of adjustment to Capacity Charge for gross heating value	Both components of the tariff (throughout and capacity) are appropriately adjusted for changes in gross heating value of gas
2.2.4	Revised arrangements for overruns	Alignment with provisions in APA Group's standard form terms and conditions for a Firm Service. Inclusion of Authorised Overrun in AA as facility is valued by Users.
2.2.5	Revision to term of Firm Service to five years	Five year term for the Firm Service is consistent the Reference Service sought by a significant portion of the market. The Firm Service is rarely sought for a term less than 5 years.
2.2.6	Reference to Firm Service, in place of Reference Service	Alignment with standard form for APA Group access arrangements
2.3	Revised arrangements for Negotiated Services	Alignment with revised extensions and expansions arrangements
3	Revisions to former reference tariff policy	Move from Gas Code to National Gas Law and Rules Text in Part 3 identical to that approved by the AER in respect of the AGP access arrangement, one revision to reference revenue rather than a defined term.
4.1	Inclusion of section on general Services and Reference Tariff policy	Text identical to that in reference tariff policy in previous access arrangement (former clause 4.1(a))
4.2	Reference to Firm Service and Firm MDQ Details of tariffs, charges and allowances moved to Details schedule	Alignment with terms in APA Group's standard form terms and conditions for a Firm Service Alignment with standard form for APA Group access arrangements
4.3	Revised arrangements for overruns, imbalances and variances	Alignment with provisions in APA Group's standard form terms and conditions for a Firm Service

	Details of tariffs, charges and allowances moved to Details schedule	
4.3.1	Removal of overrun charges of overruns at receipt points	Alignment with provisions in APA Group's standard form terms and conditions for a Firm Service
4.3.4	Removal of details on the additional of receipt and delivery points	Details included in APA Group's standard form terms and conditions
4.5	Revisions to the Reference Tariff Adjustment Mechanism	Reference Tariff Adjustment Mechanism is discussed in section 9.6 of this submission Changes to the Reference Tariff Adjustment Mechanism have led to the deletion of the following terms: Adjustment Date and Net Financial Effect; and the inclusion of the following terms: Relevant Tax and Tax.
5	Revisions to capacity trading requirements	Move from Gas Code to National Gas Law and Rules. Text in Part almost identical to that approved by the AER in respect of the AGP access arrangement.
6	Revisions to the Queuing Policy	Queuing Policy is discussed in section 10 of this submission
7	Revisions to Extensions and Expansions	Extensions and Expansions requirements are discussed in section 1.4.4 of this submission
-	Removal of Capacity Management Policy	Capacity Management Policy no longer required under National Gas Rules
Schedule 1	Inclusion of new details schedule Revisions to rates and allowances	Alignment with standard form for APA Group access arrangement Alignment with provisions in APA Group's standard form term and conditions for a Firm Service, as approved for the AGP AA
Schedule 2	New and revised definitions	New and revised definitions have been included in respect of the Queensland STTM, inclusion of Authorised Overruns in the AA, revisions to the

		Assignment provisions, standardisation of the description of the Firm service, revisions to the Liability provisions, and to address Queensland specific matters.
Schedule 3	Revisions to Terms and Conditions	Terms and Conditions have been revised to be consistent with APA Group's standard form terms and conditions. Text in Schedule 3 is as per the AER approved Amadeus Gas Pipeline Access Arrangement, with any changes to that version noted (in marked-up version of the access arrangement provided with this submission) and described in Schedule B.
Schedule 4	Connection Facilities to the Pipeline	Text is as per previous access arrangement, with changes limited to definitional changes references to Service Provider
Schedule 5	Gas Specification	Both the current and Prior Gas Specification are as per the previous access arrangement
Schedule 6	Request for Service	Revisions to this section necessary to align with processes under the revised queuing policy. Deletion of clause (c) of Prudential Requirements as overlaps with clause 2 of the terms and conditions.
Schedule 7	Pipeline Map	Updated map showing current configuration of the RBP

B Description of standard terms and conditions

Clauses	Provision	Reason for provision/variation
1	Obligation to provide the Firm Service	Clause establishes Service Provider's obligation to provide the Firm Service (Reference Service) to Users that have signed a Transportation Agreement to provide the Firm Service as set out in Schedule 3.
2	Prudential requirements	Clause sets out prudential requirements for the provision of the Firm Service, including conditions under which Service Provider can seek financial security, and circumstances where Service Provider can refuse to provide or suspend the provision of the Firm Service. Revised terms and conditions provide more security to Users with respect to the suspension of services than the previous AA.
3-10	Nominations	Sets out arrangements for User Nominations. Consistency across APA Group Pipelines in respect to this process is highly desirable. Revisions to definition of nomination deadline to align deadline with STTM provisions. Clauses 7-10 are necessary inclusions in the access arrangement to support the Queensland STTM. New clauses also introduce definition of Brisbane Hub. Definition of STTM Rules has also been revised to describe Queensland law.
11-14	Scheduling	Sets out arrangements for Scheduling of Gas. Consistency across APA Group Pipelines in respect to this process is highly desirable. APTPPL has retained authorised overruns in the RBP AA – this is a revision from the AGP AA. Facility is valued by Users. Scheduling priority has quantities under Firm Transportation Agreements up to MDQ for firm services scheduled first, then other Users with a contracted MDQ (Negotiated Services with an MDQ), then Authorised overruns, then Gas nominated by Users that do not have a contracted MDQ (usually

		interruptible services or similar). Revision to include Authorised Overruns also requires new definitions for Authorised Overrun, Authorised Overrun Quantity, Unauthorised Overrun and Unauthorised Overrun Quantity, and revised definition for Overrun in Schedule 2. Change to clause 11 and revisions to definitions for Nomination, Schedule and Delivery Point necessary to support the Queensland STTM.
15-16	Curtailment	Sets out priorities for curtailment. Priorities set are consistent with Scheduling Priorities and include Authorised Overruns. Changes to clause 16 clarify that failure to Schedule Gas because of allowable reasons listed is equivalent to interruption or curtailment for those reasons. Deletion of clauses 12 and 13 from the standard terms and conditions as clauses covering equivalent issue in existing access arrangement body at clause 2.2.3.
17-20	MOS	New clauses in respect of the Market Operator Service necessary to support the Queensland STTM. Clauses also introduce need for definitions for MOS Increase Quantity, MOS increase offer, MOS Decrease Quantity and MOS decrease offer, and changes to the definition for Imbalance.
21-25	Imbalances	Creates obligation on Users to use reasonable endeavours to match receipts and deliveries, except to the extent that they have an Authorised Imbalance, as well steps to be taken to correct an Unauthorised Imbalance. Changes to clause 21 are necessary for the introduction of STTM in Queensland
26	Adjustment to Rates and Charges/ Additional Payment	Provides that the Reference Tariff varies as per the Reference Tariff Adjustment Mechanism. Deletion of clause on GST as this is repeated in the AA body.

27-32	System Use Gas and Line Pack	Sets out provisions for System Use Gas and Line Pack, including ownership. Changes to these clauses are necessary to support the Queensland STTM, as well as alignment with AA in respect of the definition of the Firm Service.
33-38	Operation of Pipeline	These clauses set out the Service Provider's obligations with respect to operating and maintaining the pipeline, as well as processes to carry out works on the pipeline.
39-44	Metering	These clauses set out Service Provider and User obligations in respect of metering, and the process for changing those requirements.
45-52	Quality	These clauses set out the Users and Service Provider's obligations with respect to the Gas Specification. Revisions to these clauses from those approved by the AER for the AGP AA are necessary to support the two Gas Specifications currently in operation on the RBP. This situation arises because of Prior Agreements that set the Gas Specification at a different level to the current specification. Revisions to these clauses (including additional clause 48) reinstate aspects of the prior RBP AA into Service Provider's standard terms and conditions. Additional and revised definitions associated with these provisions relate to Prior Agreements, Prior Gas Specifications, and the inclusion of two Gas Specifications in the Schedules. Clauses 50-52 have been revised to included reference to the transportation of Gas, as APTPPL has little ability not to accept receipt of Off-Specification Gas.
53-55	Receipt Pressures	These clauses specify the User's obligations in respect of gas supplied at Receipt Points. The definition of Maximum Allowable Operating Pressure has been revised to include the maximum pressures for each pipeline making up the RBP.
56-59	Possession of gas and responsibility	These clauses specify possession of gas and responsibility for Gas once it has been received at a Receipt Point, including Service Provider's liability for losses while Gas is in Service Provider's control.

60	Warranties & Representations	These clauses set out the User's responsibilities in respect of title to Gas at the time of supply to the Receipt Point, as well as the accuracy of contract reference information provided to Service Provider. Revisions to these clauses are necessary to support the Queensland STTM .
61-63	Title	These clauses specify arrangements for return of undelivered Gas to a User on termination of a Transportation Agreement (net of System Use Gas), and the Title to Gas received by Service Provider.
64-68	Allocation of receipts and deliveries	These clauses set out arrangements for allocation of Gas received or delivered on a Day that is not equal to the quantities Scheduled on any Day. Revisions to these clauses are necessary to support the Queensland STTM. These revisions introduce new definitions for STTM Shippers, MOS gas and overrun MOS.
69-74	Addition of Receipt Points and Delivery Points	These clauses set out the process for a User to request the addition of a Receipt or Delivery Point on the Pipeline, and Service Provider's response to that request.
75- 77	Dispute Resolution	These clauses set out arrangements for the resolution of disputes between the parties to the Gas Transportation Agreement, including scope to refer certain issues to an independent expert for resolution.
78-80	Default	These clauses set out the arrangements in respect of Default by the party to the Gas Transportation Agreement.
81-84	Billing & Payment	These clauses set out the User's and Service Provider's obligations in respect to billing and payment.
85-86	Information Interface	These clauses relate to the User's use of an Information Interface provided by Service Provider.
87-91	Limitation of Liability & Indemnity	These clauses set out liability and indemnity arrangements in the Gas Transportation Agreement. Liability for Gross Negligence was included by the AER in the AGP AA. APTPPL has included a definition of Gross Negligence/Wilful Misconduct in the AA to provide certainty and clarity around the meaning of

		this term. Additional clause 91 is necessary to support the Queensland STTM
92-97	Force Majeure	These clauses set out arrangements for Force Majeure Events. The AER imposed changes to these provisions in respect of the AGP AA that APTPPL considers introduces unacceptable risk to APTPPL. Service Provider has inserted the word 'reasonable' in relation to the test for the 'control' of a Party. Service Provider submits that FM should include events which may be within the 'control' of a party but not its 'reasonable' control. An example of this is a strike or lockout. Service Provider notes that there are other protections from a Party calling FM unnecessarily. Service Provider has included in 92 (g) loss and damage to machinery and facilities which otherwise meet the test for FM. Service Provider's changes to clauses 92 and 93 reflect Service Provider's standard gas transportation agreement.
98-100	Assignment	Assignment clause provides for reciprocal assignment restrictions. Changes include more detail regarding when consent cannot be unreasonably withheld. Provision is also made with respect to change in control in recognition that this is a common occurrence in the industry. Revisions to these clauses introduce the need for a definition of Change in Control and Affected Party.
101-103	Confidentiality	These clauses set out arrangements for using and disclosing Confidential Information.

C RIN Requirements Index

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
2.	Service provider details and business context				
2.1	Details of service providers				
(a)	Provide the following information for all service providers:				
(a) (i)	Trading name				1.2
(a) (ii)	Type of legal entity				1.2
(a) (iii)	Australian Company Number or Australian Business Number				1.2
(b)	Type of service provider (owner, controller or operator)				1.2
	Local agent of service provider				
2.2	Provide details of any *local agent(s)* of the *service provider* (see s. 11, NGL).				1.2
2.3	If there is no *local agent* of the *service provider*, provide a statement to that effect.				1.2
2.4	If any service provider is a foreign company and has appointed a local agent, provide the local agent's:				
(a)	Trading name.				N/A
(b)	Australian Company Number or Australian Business Number.				N/A
(c)	Business and postal address(es).				N/A
(d)	Contact person(s).				N/A
(e)	Relevant contact details.				N/A
	Service provider acting on behalf of other service providers				
2.5	Provide details of any service provider(s) acting on behalf of another service provider (see s. 10, NGL).				N/A
2.6	If there is no service provider acting on behalf of other service providers, provide a statement to that effect.				N/A
2.7	If there is a *service provider* acting on behalf of other *service providers*:				
(a)	Identify which service provider is acting on behalf of the other service providers in relation to APTPPL's Access Arrangement Proposal.				N/A
(b)	Provide that service provider's business				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	and postal address(es).				
(c)	Provide a contact person(s) and relevant contact details for that service provider.				N/A
3.	Background to the pipeline				
	Pipeline and pipeline services				
3.1	Provide:				
(a)	The identification of 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.	1.3			1.3
(b)	Describe the pipeline services APTPPL proposes to offer to provide by means of the pipeline.	2.1			1.4.9
(c)	Specify the reference services identified in the response to 3.1(b).	2.2			1.4.9
(d)	Explain how the proposed reference services are those that are sought by a significant part of the market.				1.4.9
	Demand				
3.2	Provide:				
(a)	Minimum, maximum and average demand for the Current Access Arrangement Period and forecast minimum, maximum and average demand for the Next Access Arrangement Period for each receipt or delivery point.			12	3.1
(c)	Actual and estimated user numbers for the Current Access Arrangement Period and forecast user numbers for the Next Access Arrangement Period for each receipt or delivery point.			12	3.1
3.3	Provide:				
(a)	Details of the key drivers behind the demand forecasts.				3.4
(b)	The methodology that has been used to develop the demand forecasts, including the key assumptions and inputs that have been used and how demand for pipeline				3.4

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	services is differentiated.				
(c)	An explanation of how the demand forecasts have been used to develop APTPPL's capital expenditure and operating expenditure forecasts.				3.3
(d)	An explanation of any trends of demand and volumes over the Current Access Arrangement Period and the Next Access Arrangement Period.				3.6
	Pipeline capacity and utilisation				
3.4	Provide				
(a)	Actual or estimated pipeline capacity and utilisation of pipeline capacity for the Current Access Arrangement Period.			12	
(b)	Forecasts of pipeline capacity and utilisation of pipeline capacity for the Next Access Arrangement Period.			12	
(c)	The basis on which the forecasts have been derived.				3.3
(d)	Details of the key drivers behind the forecasts.				3.4
(e)	The methodology that has been used to prepare the forecasts, including the key assumptions and inputs that have been used.				3.4
(f)	An explanation of how the forecasts have been used to develop the capital expenditure and operating expenditure forecasts.				3.4
(g)	An explanation for any trends of pipeline capacity and utilisation over the Current Access Arrangement Period and Next Access Arrangement Period.				3.6
4.	Return on the projected capital base				
	Opening capital base at the beginning of the current access arrangement period				
4.1	Provide:				
(a)	The opening capital base by asset class for each year of the Current Access Arrangement Period.			1	5.3.1

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(b)	The capital base approved by the jurisdictional regulator for each year of the Current Access Arrangement Period.			1	5.1
(c)	The remaining asset lives that reflect the capital base as at 1 July 2007 and the asset lives that reflect the capital base as approved by the jurisdictional regulator for each year of the Current Access Arrangement Period.			4	5.2
(d)	A reconciliation of the opening capital base provided in response to Error! Reference source not found.Error! Reference source not found. and Error! Reference source not found.Error! Reference source not found. , including adjustments for any difference in estimated and actual capital expenditure, other adjustments made to the opening capital base as at 1 July 2007, and an explanation for these variations.				5.1
(e)	Reconciliation of any changes in asset classes between the Current Access Arrangement Period and the Next Access Arrangement Period.				N/A
	Capital expenditure in the current access arrangement period				
4.2	Provide an explanation for:				
(a) (i)	Any significant variations (i.e. a difference of more than 10 per cent) between capital expenditure approved by the jurisdictional regulator and the actual and/or estimated capital expenditure for the Current Access Arrangement Period.				4.4
(a) (ii)	Whether and how APTPPL considers that conforming capital expenditure added to the capital base in the Current Access Arrangement Period meets the requirements of section 8.16 of the Code.				4
4.3	By asset class for each year of the Current Access Arrangement Period, provide an explanation for				
(a)	Amounts added to the opening capital base for conforming capital expenditure.				4.4
(b)	Amounts for non conforming capital expenditure identified as recovered by				5.3.1

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	surcharge, added to a speculative capital expenditure account (under the code a speculative investment fund), and other amounts of non conforming expenditure.				
	Past capital contributions, speculative capital expenditure account (under the code speculative investment fund), reused redundant assets, redundant assets, disposals in the current access arrangement period				
4.4	Provide an explanation for whether and how APTPPL considers:				
(a)	Amounts added to the opening capital base from the speculative capital expenditure account (under the Code, a speculative investment fund) meet the requirements of section 8.16 of the Code.				N/A
(b)	Amounts added to the opening capital base for the reuse of redundant assets meet the requirements of section 8.16 of the Code.				N/A
4.5	Provide details about whether assets which comprise the opening capital base are or have been subject to compensation claims through, legal or court action, insurance or other processes, including details about the particular assets subject to such claims, time period of such claims, and the relevant class of assets to which these assets belong.				5.1
4.6	Provide by asset class for each year of the Current Access Arrangement Period:				
(a)	Amounts added to the opening capital base for capital contributions.				N/A
(b)	Amounts added to the opening capital base from the speculative capital expenditure account (under the Code a speculative investment fund).				5.3
(c)	Amounts added to the opening capital base for the reuse of redundant assets.				5.3
(d)	Amounts deducted from the opening capital base for redundant assets.				5.3
(e)	Amounts deducted from the opening capital base for disposals.				5.3
	Depreciation in the Current Access Arrangement Period				

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
4.7	For each year of the Current Access Arrangement Period, provide:				
(a)	For each asset, class amounts deducted from the opening capital base for depreciation including amounts of depreciation for changes to the capital base in the Current Access Arrangement Period, including distinguishing depreciation referable to the opening capital base and amounts added to, or deducted from, the opening capital base for:			4	
(a) (i)	Re-used redundant assets, redundant assets.			4	
(a) (ii)	Disposals.			4	
(a) (iii)	Conforming capital expenditure.			4	
(a) (iv)	Capital contributions included in the capital base.			4	
(a) (v)	Amounts from the speculative from the speculative capital expenditure account (under the code a speculative investment fund).			4	
(b)	Asset lives of each asset.			4	5.2.1
	Rate of inflation and adjustment to the capital base in the current access arrangement period				
4.8	Provide:				
(a)	The actual or estimated rates of inflation used to adjust the capital base for inflation over the Current Access Arrangement Period.			1	6
(b)	The adjustments to the capital base for inflation over the Current Access Arrangement Period.			1	5.3
	Capital base in the current access arrangement period				
4.9	Provide the capital base by asset class for each year of the current access arrangement period.			1	5.3
	Forecast conforming capital expenditure in the access arrangement period				
Note: The opening capital base for the Next Access Arrangement Period is derived from the capital base for the Current Access Arrangement Period (refer to clause 4.9 of this Notice)					

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
4.10	Provide:				
(a)	Amounts by asset class for each year of the Next Access Arrangement Period for forecast conforming capital expenditure.			1	4.5
(b)	The extrapolation rates, where applicable, used in deriving forecast conforming capital expenditure.				4.5
4.11	Provide the following information about forecast conforming capital expenditure:				
(a)	A definition and explanation of any materiality threshold test that APTPPL intends to use.				N/A
(b)	The nature of forecast conforming capital expenditure projects or programmes material to an asset class, including a brief description of the capital expenditure and the location on the transmission pipeline.				4.5
(c)	Any assumptions used in deriving the forecast conforming capital expenditure (see Rule 75), including the specific rate used in each year of the access arrangement period, whether the rate is in real or nominal terms, and how the derivation or extrapolation has been developed (including source material).				4.5
(d)	Any relevant internal decision making documents relating to approval of the forecast capital expenditure and any other internal or external documentation or models that justify the forecast conforming capital expenditure, including but not limited to business cases, feasibility studies, forecast demand studies and internal reports and the date of any relevant internal decision making body/management decisions.				4.5. Attach 4.1
(e)	Details as to whether the forecast conforming capital expenditure is to be funded by parties other than the APTPPL.				N/A
(f)	Details of contractual agreements with parties where capital contributions are made by users to new capital expenditure				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	(see Rule 82).				
(g)	An explanation of whether and how APTPPL considers that the forecast capital expenditure conforms with the criteria listed in Rule 79(1).				4.5
(h)	Whether and how APTPPL considers that the forecast capital expenditure is justifiable under Rule 79(2) including any sub rule in 79(2) is relied on.				4.5
4.12	If Rule 79(2)(a) is relied on to justify new capital expenditure, provide:				
(a)	An explanation and quantitative analysis which demonstrates whether and how APTPPL considers that the capital expenditure is justifiable under Rule 79(2)(a).				Attach 4.3
(b)	An explanation of the nature and quantification of the economic value that directly accrues to the service provider, gas producer, users and end users (see Rule 79(3)).				Attach 4.3
4.13	If Rule 79(2)(b) is relied on to justify new capital expenditure, provide an explanation of whether and how APTPPL considers that the capital expenditure is justifiable under Rule 79(2)(b), including:				
(a)	Relevant information and documentation.				N/A
(b)	A description of the incremental service or services (see Rule 79(4)(a)).				N/A
(c)	The incremental revenue (see Rule 79(4)(b)).				N/A
(d)	The incremental expenditure (see Rule 79(4)(b)).				N/A
(e)	Quantitative analysis that demonstrates whether and how APTPPL considers that the capital expenditure is justifiable under Rule 79(2)(b), showing:				N/A
(e) i	The present value of expected incremental revenue including whether and how APTPPL considers that it is determined consistent with Rules 79(4) (a) and 79(4) (b).				N/A
(e) ii	The discount rate that is used to determine the present value is equal to the rate of return implicit in the reference				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	tariff.				
(e) iii	The present value of the expected incremental expenditure.				N/A
4.14	If Rule 79(2)(c)(i), (ii) or (iii) is relied on to justify new capital expenditure, provide:				
(a)	An explanation of what item in Rule 79(2) (c) (i), (ii) or (iii) is relied on.				Attach 4.2
(b)	The relevant regulatory obligation or requirement (if any) and the relevant authority or body enforcing it.				Attach 4.2
(c)	An explanation of whether and how APTPPL considers that the forecast capital expenditure satisfies the item in Rule 79(2)(c)(i), (ii) or (iii) being relied on.				Attach 4.2
(d)	Supporting technical or other external or internal reports about whether and how APTPPL considers that the forecast capital expenditure addresses the relevant item in Rule 79(2) (c) (i), (ii) or (iii).				Attach 4.2
4.15	If Rule 79(2)(c)(iv) is relied on to justify new capital expenditure in APTPPL's Access Arrangement Proposal, provide:				
(a)	An explanation of the change in demand for existing services necessitating the new capital expenditure, including a measure of the change in demand.				N/A
(b)	Reports or other information and documentation that supports whether and how APTPPL considers that the forecast capital expenditure will meet the increase in demand for existing services.				N/A
	Capital expenditure that is not conforming in the next access arrangement period				
4.16	Provide:				
(a)	The amount by asset class for each year of the Next Access Arrangement Period for forecast non conforming capital expenditure classified into non conforming capital expenditure forecast to be recovered through surcharges, non conforming capital expenditure forecast to be added to the speculative capital expenditure account, and other non conforming capital expenditure.			N/A	N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
(b)	Details of the forecast speculative capital expenditure account by asset class for the Next Access Arrangement Period.			N/A	N/A
(c)	A justification for the different rate of return, if the balance of the speculative capital expenditure account increases at a rate different to the rate of return implicit in a reference tariff (see Rule 84(2)).				N/A
(d)	The amount of forecast capital contributions by asset class for each year of the Next Access Arrangement Period.			1	N/A
(e)	The amount of capital contributions by asset class for each year of the Next Access Arrangement Period proposed to be rolled into the capital base under Rule 82(3).			1	N/A
(f)	Where relevant, the extrapolation rates used in deriving forecasts for capital expenditure other than conforming capital expenditure, if different from extrapolation rates provided in Error! Reference source not found. (b) of this Notice.			1	N/A
(g)	Details of the mechanism to prevent APTPPL from benefiting, through increased revenue, from the capital contributions by a user in the Next Access Arrangement Period (see Rule 82(3)).				N/A
	Capital redundancy policy in the next access arrangement period				
4.17	If relevant, provide in APTPPL's Access Arrangement Proposal:				
(a)	An explanation of the proposed mechanism to remove redundant assets from the capital base including when the mechanism will take effect and whether the mechanism includes a proposal for cost sharing between the service provider and users associated with a decline in demand for pipeline services.				1.4.6
(b)	A justification for the mechanism.				1.4.6
(c)	Explain what uncertainty the mechanism may cause.				1.4.6

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
(d)	The effect of this uncertainty on the service provider.				1.4.6
	Forecast disposals in the next access arrangement period				
4.18	Amounts by asset class for each year of the Next Access Arrangement Period for forecast disposals.			1	1.4.6
	Rate of inflation and adjustment to the projected capital base in the access arrangement period				
4.19	Provide:				
(a)	The adjustment to the capital base to take account of the effects of inflation over the Next Access Arrangement Period.			1	5.3.2
(b)	The rates of inflation used to adjust the capital base over the Next Access Arrangement Period.			1	6.9
	Projected capital base in the next access arrangement period				
4.20	Provide the capital base by asset class for each year of the Next Access Arrangement Period.			1	5.3.2
5	Rate of return for the projected capital base				
	Weighted average cost of capital and CAPM				
5.1	If APTPPL intends to use the WACC methodology and CAPM methodology, provide:				
(a)	The values of each of the parameters that comprise the WACC methodology and CAPM methodology.				6.10
(b)	A justification for the values of each of the parameters used in the WACC derivation.				Ch 6 Attach 6.1, 6.2, 6.3
(c)	An explanation about whether and how APTPPL considers that the proposed rate of return complies with Rule 87.				Ch 6 Attach 6.1, 6.2, 6.3
	Method other than weighted average cost of capital and CAPM				
5.2	If APTPPL does not intend to use the WACC methodology and/or CAPM methodology, in APTPPL's Access Arrangement Proposal, provide:				
(a)	An explanation of the proposed methodology for the rate of return.				N/A
(b)	A quantification of the rate of return using				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	this methodology including any justification for the use of parameters in this methodology.				
(c)	An explanation about whether and how APTPPL considers that the proposed rate of return complies with Rule 87.				N/A
	Rate of return and taxation method				
5.3	Provide:				
(a)	Details of the proposed method for dealing with taxation and a demonstration of how the tax allowance is calculated.				Ch 7
(b)	Where a pre-tax rate of return is proposed, provide an explanation of whether and how APTPPL considers that the proposed tax rate complies with Rule 74(2).				N/A
Refer also to clause Error! Reference source not found. of this Notice for further information requirements relating to the treatment of taxation.					
	Cost of Debt				
5.4	Debt Instruments – *See response to s42 Notice*.				
(a)	Identify all Debt Instruments.				
(b)	Provide a description of each Debt Instrument identified in the response to paragraph 5.4(a), including:				
(b) (1)	Its type.				
(b) (2)	Its commencement date.				
(b) (3)	Its maturity date.				
(b) (4)	The quantum of debt in Australian dollars at its commencement date.				
(b) (5)	If it was foreign issued, the country it was issued from, the currency of the debt issued, and the quantum of the debt in this currency at its commencement date.				
(b) (6)	Whether it was a private issue or public issue.				
(b) (7)	Whether it was senior or subordinate.				
(b) (8)	If the interest rate payable was fixed, the fixed rate payable, or floating, the				

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	benchmark utilised for floating payments and the margin payable above the benchmark.				
(b) (9)	Where the interest rate has been altered through the use of financial instrument(s) listed in paragraph 5.5(a), the effective fixed interest rate payable after adjusting for the financial instrument(s), or the effective floating interest rate payable after adjusting for the financial instrument(s), expressed as a benchmark utilised for floating payments and the margin payable above the benchmark.				
(b) (10)	The schedule for payments of interest and principal.				
(b) (11)	If applicable:				
(b) (11) i	Where it was issued at a discount to face value, its yield-to-maturity at its commencement date.				
(b) (11) ii	Where it was of a standby nature, the quantum of debt in Australian dollars drawn at 30 September 2011, and the maximum amount of debt available in Australian dollars.				
(b) (11) iii	Where it has a credit rating, the credit rating assigned to it by each credit rating institution that has rated it.				
(b) (11) iv	Where it included any embedded options, making it callable, putable or convertible, the nature of those options.				
5.5	Financial Instruments				
(a)	Identify all Financial Instruments.				
(b)	Provide a description of each Financial Instrument identified in the response to paragraph 5.5(a), including:				
(b) (1)	Its type.				
(b) (2)	Identifying the Debt Instrument identified in the response to paragraph 5.4(a) which it was applicable to.				
(b) (3)	Its commencement date.				

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(b) (4)	Its cessation date.				
(b) (5)	Details of any optionality, either explicit or embedded, including early exercise features, and strike or exercise price.				
(b) (6)	For swaps, if it was an interest rate swap, whether it is fixed for floating, floating for fixed or floating for floating, and if it was a currency swap, the type of currencies traded.				
(b) (7)	For options, whether it was a cap, floor, collar, foreign exchange call or foreign exchange put.				
(b) (8)	Whether it was exchange traded or over-the-counter.				
6.	Forecast depreciation				
6.1	Provide:				
(a)	Amounts for forecast depreciation disaggregated for components by asset class for each year of the Next Access Arrangement Period, including accounting for and identifying depreciation referable to the opening capital base, forecast conforming capital expenditure, other capital expenditure, forecast disposals, and other amounts that may be added or deducted to the projected capital base under the NGR.			4	5.3
(b)	Details of the asset lives for each asset			4	5.2
6.2	Provide an explanation of whether and how APTPPL considers that the depreciation schedules comply with the requirements in Rule 89(1) and (2).				5.3
7.	Estimate cost of corporate income tax				
7.1	If applicable, provide:				
(a)	An estimate of the cost of corporate income tax over the next access arrangement period.			5	7.5
(b)	Details of how the estimated cost of corporate tax is calculated.			5	7.5
Refer also to clause Error! Reference source not found. of this Notice for further information requirements in					

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
relation to the treatment of taxation					
8.	Proposed incentive mechanism				
	Existing incentive mechanism in the earlier access arrangement period				
8.1	If the Current Access Arrangement contains incentive mechanisms:				
(a)	Provide for each incentive mechanism:				N/A
(a) i	The increments for efficiency gains and decrements for efficiency losses that have occurred in the Current Access Arrangement Period.			10	N/A
(a) ii	The revenue referable to increments for efficiency gains or decrements for efficiency losses from the Current Access Arrangement Period that is to be carried over (from the Current Access Arrangement Period) into the Next Access Arrangement Period for existing incentive mechanisms.			10	N/A
(b)	Provide for each incentive mechanism:				N/A
(b) i	An explanation of the incentive mechanism and its operation for the Current Access Arrangement Period.				N/A
(b) ii	An explanation of the increments for efficiency gains and decrements for efficiency losses that have occurred in the Current Access Arrangement Period and the relevant carryover amounts for the Next Access Arrangement Period.				N/A
(b) iii	All relevant analyses or reports that support the operation of the existing incentive mechanism.				N/A
	Proposed incentive mechanism in the next access arrangement period				
Note: this section also applies to incentive mechanisms already in place in the Current Access Arrangement Period that are proposed to continue for the Next Access Arrangement Period.					
8.2	Provide for each incentive mechanism (including existing incentive mechanisms) the forecast revenue referable to increments for efficiency gains or decrements for efficiency losses for the Next Access Arrangement Period.			10	N/A
8.3	Provide, for each incentive mechanism:				

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
(a)	An explanation of the incentive mechanism and its operation in the Next Access Arrangement Period.				N/A
(b)	An explanation of the rationale for any proposed incentive mechanisms, including whether and how APTPPL considers that the incentive mechanism is intended to encourage efficiency of the provision of services, and consistent with the revenue and pricing principles, with reference to those principles.				N/A
(c)	Any relevant analyses or reports that support the proposed incentive mechanism.				N/A
9.	Operating Expenditure				
	Operating expenditure in the current access arrangement period				
9.1	Provide actual and estimated operating expenditure by category for each year of the Current Access Arrangement Period.				8.1.3
	Forecast operating expenditure in the access arrangement period				
9.2	Provide operating expenditure forecasts by category for each year of the Next Access Arrangement Period.			6	8.2
9.3	Provide:				
(a)	A description and explanation of the change in operating expenditure categories between the Current Access Arrangement Period and the Next Access Arrangement Period.				8.2.5
(b)	A description and explanation of the nature of material forecast operating expenditure in an operating expenditure category including a definition of the materiality threshold used, and whether there have been changes to the operations of the pipeline from the Current Access Arrangement Period that have resulted in material changes to operating expenditure categories and total operating expenditure in the Next Access Arrangement Period.				8.1.3
(c)	An explanation of whether and how				8.1.3

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	APTPPL considers that the proposed operating expenditure complies with Rule 91, with particular reference to operating expenditure identified in clause 9.3(b).				
(d)	Any assumptions used in deriving the forecast operating expenditure.				8.1.3
9.4	Where relevant, provide:				
(a)	The specific extrapolation rate used in deriving operating expenditure forecasts for each year of the Next Access Arrangement Period.				8.2.5.1
(b)	Whether the rate is in real or nominal terms.				8.2.5.1
(c)	How the derivation or extrapolation rates used have been developed (including source material).				8.2.5.1 Attach 8.3, 8.4
Note these may include the unit rates used for key items of expenditure, how these have been developed (including source material) and evidence that they reflect efficient costs and specific rates used to derive or extrapolate expenditure estimates (for example, labour and materials)					
	Self insurance				
9.5	For each self insurance event provide the forecast annual insurance premiums for each year of the Next Access Arrangement Period.				AAPTPPL makes no claim for Self insurance
9.6	Provide the following information for each self insurance event:				
(a)	The name and a description of the event.				N/A
(b)	Whether the event is in relation to a particular asset or class of assets and, if so, identify those assets.				N/A
(c)	Reasons for self insuring the event.				N/A
(d)	If the event has not previously been self insured, reasons why it is now being proposed to be self insured and how the risk of the event was treated in the Current Access Arrangement.				N/A
(e)	If a proposed self insurance event was previously insured externally, details of existing or previous insurance policies and reasons why external insurance is not being proposed for the Next Access				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	Arrangement Period.				
(f)	Any quotes obtained from external insurers.				N/A
(g)	Details of how the premiums were calculated, including any underlying assumptions used to derive the premiums.				N/A
(h)	Any consultant's report relied on by the APTPPL in deriving the estimates.				N/A
(i)	A copy of APTPPL's decision making body's resolution (including the date of the resolution) to self insure the event(s).				N/A
(j)	Details of the Procedures, Policies and Strategies that:				N/A
(j) i.	Explain how the self insurance risk is to be reported (if required under relevant accounting standards) in APTPPL's audited financial statements.				N/A
Note: This may include relevant documents that were prepared or submitted for ASIC or other relevant government authority					
(j) ii.	Explain the procedure for notification, and information that will be provided, to the AER if a self insurance event occurs.				N/A
	Outsourced operating and capital expenditure				
9.6	For operating expenditure that is material to an operating expenditure category and capital expenditure that is material to an asset class, and is forecast to be incurred in the Next Access Arrangement Period but provided by a party other than the service providers (i.e. outsourced), provide:				
(a)	Define the materiality threshold used and provide an explanation for why it was chosen.				4.4.2
(b)	The name of the party(ies) and the contract.				N/A
(c)	Details of how the contract was awarded (for example, by competitive tender).				N/A
(d)	Details of fees and charges in the contract and a description of the goods or services provided.				N/A
(e)	The commencement date and term of the contract.				N/A

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
(f)	Reasons why the functions were outsourced.				N/A
(g)	Details of the relationships with the party or parties named in response to clause 0Error! Reference source not found. including if a party to the contract is an associate of any of the service providers of the pipeline.				N/A
	Taxation asset base				
10.1	Regardless of the methodology APTPPL adopts for taxation, provide the following information forecast as at 30 June 2012:				
(a)	Tax standard life for each asset class.				5.2
(b)	Remaining tax life for each asset class.				5.2
(c)	Tax asset base or remaining tax asset value for each asset class.				7.4
(d)	An estimate of the carry forward tax loss.				7.6
11.	Tariffs				
	Revenue equalisation				
11.1	Provide details demonstrating that the net present value of the proposed revenue stream is equal to the net revenue stream generated from the building block approach for each reference service.			8	9.8
	Total revenue allocation				
11.2	Provide the allocation of costs to services, including:				
(a)	Identify and quantify cost pools according to relevant asset classes and operating cost categories for the direct costs of reference services, the direct cost of pipeline services other than reference services, and other costs from building block revenue and rebateable services.			9	9.3
(b)	Reconcile total revenue for pipeline services allocated to reference services and other services.			9	9.3.1
11.3	Provide:				
(a)	An explanation of the nature of the methods or principles used to allocate relevant cost pools, including an				9.3.1

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	explanation of whether and why APTPPL considers that these methods or principles provide the best estimate, and an analysis to support their derivation.				
(b)	For rebateable services, a description of the mechanism that APTPPL will use to apply an appropriate portion of the revenue generated from the sale of rebateable services to price rebates (or refunds) to users of reference services (see Rule 93).				N/A
	Tariffs – transmission pipelines				
11.4	If relevant, provide for the Next Access Arrangement Period:				
(a)	The costs directly attributable to each reference service.				9.3, 9.8
(b)	Other costs attributable to each reference service.				9.3, 9.8
(c)	The costs directly attributable to supplying each reference service to a particular user or class of users and where relevant other users or classes of users.				N/A
(d)	Other costs attributable to supplying each reference service to a particular user or class of users and where relevant other users or classes of users.				N/A
11.5	Provide:				
(a)	Costs directly attributable to each reference service.				9.3, 9.8
(b)	Other costs that are attributable to reference services.				9.3, 9.8
(c)	Where relevant, explain the nature of costs directly attributable and other costs attributable for the user or class of users, and other users or classes of users.				9.3
(d)	An explanation of the methodology used to allocate costs for the information provided in response to clause 0.				9.3
	Prudent discounts (see Rule 96)				
11.6	Provide:				

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
(a)	Full details and justification of all prudent discounts.				9.4
(b)	A demonstration of how a prudent discount is necessary to respond to competition or maintain efficient use of the pipeline.				9.4
(c)	A demonstration (by quantifying the effect) that without the prudent discount, reference tariffs would be higher than what they would be with the prudent discount.				9.4
12.	Reference tariff variations				
	Tariff variation mechanism				
12.1	Provide:				
(a)	An explanation of the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism.	4.5.1			9.6
(b)	An explanation of whether and how APTPPL considers that reference tariff variation mechanism address the factors contained in Rule 97(3).				9.6
Note: In doing so, the service provider needs to establish a materiality level for events that will be passed-through for the AER to have regard to the possible effects of the reference tariff variation mechanism on the administrative costs of the AER, the service provider and users or potential users.					
(c)	An explanation of whether and how APTPPL considers that the reference tariff variation mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)).				9.6
	Cost pass through mechanism				
12.2	Provide:				
(a)	A definition and description of each cost pass through event.	4.5.2			9.6
(b)	An explanation of whether and how APTPPL considers that the proposed the cost pass through mechanism addresses the factors contained in Rule 97(3).				9.6
(c)	A description and explanation of whether				9.6

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
	and how APTPPL considers that each cost pass through event is relevant to a building block component mentioned in Rule 76, is uncontrollable i.e. a prudent service provider through its actions could not have reasonably prevented the relevant pass through event from occurring or substantially mitigated the cost impact of the pass through event, and how the costs of the event are not already provided for through the operational expenditure or capital expenditure forecasts, through the WACC (events which affect the market generally and not just the provider are systemic risk and already compensated through the WACC), or through any other mechanism or allowance.				
(d)	An explanation of whether and how APTPPL considers that the cost pass through mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)).				9.6
Note: Rule 97(4) and Rule 97(3) require a service provider to explain the administrative arrangements for cost pass through events and their relationship to other periodic reviews for other tariff variation mechanisms (especially timing of notifications to the AER).					
13.	Non-Tariff Components				
	Queuing Requirements				
13.1	Provide:				
(a)	Details of the process or mechanism for order of priority for spare or developable capacity, (for example, whether it is to be as a first-come-first-served basis or by auction).	6			10
(b)	Enough detail about the queuing requirements to enable users to understand the basis on which an order of priority between them has or will be determined, and if an order of priority has been determined, to determine the prospective user's position in the queue.	6			10
	Capacity trading requirements				

RIN Reference		AA Proposal	AA Info	RIN Template	Sub-mission
13.2	Provide an explanation of whether or not APTPPL is, or will be, subject to the rules of a gas market and, if so, which rules.				
13.3	If APTPPL is not, or will not, be subject to the rules of a gas market, explain the conditions under which APTPPL:				
(a)	Will or will not consent to the transfer of all or any of a user's contracted capacity to a third party.	5.2 & 5.3			1.4.7
(b)	Relevant conditions users must comply with (including technical and commercial considerations).	5.2 & 5.3			1.4.7
	Extension and expansion requirements (see Rule 104)				
13.4	Provide:				
(a)	Details of any extension and expansion requirements including whether the access arrangement will apply to incremental services to be provided as a result of the extension or expansion.	7			1.4.4
(b)	Details of the effect of the extension or expansion on tariffs.	7			1.44
(c)	Sufficient detail of the conditions under which APTPPL will or will not consent to an extension or expansion of the capacity of the pipeline, and for conditions under which consent is given, to provide funds for work involved in making an extension or expansion.	N/A			N/A
	Change of receipt or delivery point by user				
13.5	Provide:				
(a)	Information identifying the principles for the change of a user's receipt or delivery point including how users may obtain consent to change receipt or delivery points.	5.4			1.4.8
(b)	Where relevant, the conditions under which APTPPL will or will not give consent to a change of a receipt or delivery point and the conditions that users must comply with for APTPPL to give its consent.	5.4			1.4.8
(c)	Where APTPPL specifies in advance conditions under which it will not consent	5.4			1.4.8

RIN Reference	AA Proposal	AA Info	RIN Template	Sub-mission
to a change in a receipt or delivery point, the conditions and the technical and commercial considerations which give rise to APTPPL specifying the conditions.				