



# **N.T. Gas Pty. Limited**

**In trust for the Amadeus Gas Trust**

ABN 68 348 460 818

ACN 050 221 415

## **Amadeus Gas Pipeline**

### **Access Arrangement Revision Proposal**

#### **Submission**

**December 2010**

**Public**





# Contents

|  |             |
|--|-------------|
| <b>Executive Summary .....</b>   | <b>ix</b>   |
| <b>Abbreviations .....</b>   | <b>xiii</b> |
| <b>1 Introduction.....</b>   | <b>1</b>    |
| 1.1 Purpose of this submission .....   | 1           |
| 1.2 Layout of this submission.....   | 1           |
| 1.3 Requirements for access arrangement revision proposal.....                       | 2           |
| 1.4 Pipeline construction, ownership and regulatory history.....                     | 4           |
| 1.5 Pipeline overview and context for the access arrangement revision proposal ..... | 7           |
| <b>2 Services.....</b>   | <b>9</b>    |
| 2.1 Pipeline services.....   | 9           |
| 2.2 Non-tariff components.....   | 12          |
| <b>3 Regulatory obligations .....</b>  | <b>17</b>   |
| 3.1 National Regulatory Obligations.....   | 17          |
| 3.2 Northern Territory Regulatory Obligations.....                                   | 18          |
| 3.3 Australian Standards and Codes.....  | 21          |
| 3.4 Regulatory reporting .....   | 23          |
| <b>4 Pipeline planning and asset management .....</b>                                | <b>25</b>   |
| 4.1 Overarching objectives .....   | 25          |
| 4.2 Planning components .....  | 25          |
| 4.3 Key planning and asset management documents.....                                 | 29          |
| 4.4 Expenditure governance .....   | 31          |
| <b>5 Pipeline demand and utilisation .....</b>                                       | <b>33</b>   |
| 5.1 Demand and utilisation during earlier access arrangement period .....            | 33          |
| 5.2 Demand and utilisation forecasts .....   | 44          |
| <b>6 Capital expenditure.....</b>  | <b>61</b>   |
| 6.1 Rules governing conforming capital expenditure.....                              | 61          |
| 6.2 Capital expenditure over the earlier access arrangement period.....              | 62          |
| 6.3 Forecast capital expenditure .....   | 83          |
| <b>7 Capital base .....</b>  | <b>90</b>   |
| 7.1 Opening capital base for the access arrangement period .....                     | 90          |
| 7.2 Projected capital base for the access arrangement period.....                    | 93          |
| <b>8 Return on capital .....</b>   | <b>101</b>  |
| 8.1 Introduction.....  | 101         |
| 8.2 Risk-free rate .....   | 103         |
| 8.3 Gearing.....   | 103         |
| 8.4 Debt margin .....  | 104         |
| 8.5 Market risk premium .....  | 109         |
| 8.6 Beta .....   | 110         |



|           |  |            |
|-----------|--|------------|
| 8.7       | Gamma.....   | 112        |
| 8.8       | Taxation rate.....   | 113        |
| 8.9       | Forecast inflation .....   | 113        |
| 8.10      | Debt raising costs .....   | 115        |
| 8.11      | WACC estimate .....  | 115        |
| <b>9</b>  | <b>Operating expenditure.....</b>  | <b>117</b> |
| 9.1       | Operating expenditure categories .....   | 117        |
| 9.2       | Operating expenditure over earlier access arrangement period .....                                       | 118        |
| 9.3       | Forecast operating expenditure .....   | 122        |
| 9.4       | Benchmarking and efficiency .....  | 135        |
| 9.5       | Outsourced expenditure.....  | 139        |
| <b>10</b> | <b>Total revenue .....</b>   | <b>141</b> |
| 10.1      | Return on capital.....   | 141        |
| 10.2      | Regulatory depreciation .....  | 141        |
| 10.3      | Corporate income tax.....  | 141        |
| 10.4      | Revenue requirement .....  | 142        |
| 10.5      | Incentive mechanisms .....   | 142        |
| <b>11</b> | <b>Tariffs .....</b>   | <b>145</b> |
| 11.1      | Revenue allocation .....   | 145        |
| 11.2      | Reference Tariff .....   | 146        |
| 11.3      | Reference tariff variation .....   | 148        |
|           | Attachment A – Information required by the National Gas Rules and AER Regulatory Information Notice..... | 155        |
|           | Attachment B – Regulatory Information Notice templates.....  | 165        |
|           | Attachment C – Planning documents .....  | 167        |
|           | Attachment D – Channel Island Meter Station project – confidential.....                                  | 169        |
|           | Attachment E – Models .....  | 171        |
|           | Attachment F – Details of outsourced expenditure – confidential .....                                    | 173        |
|           | Attachment G – Estimating a WACC for the NT Gas Transmission Pipeline .....                              | 175        |
|           | Attachment H – WACC information – confidential .....   | 177        |
|           | Attachment I – Operating expenditure base year adjustments and step changes – confidential .....         | 179        |



## List of tables

|  |     |
|--|-----|
| Table 1.1 – Delivery points and laterals along the Amadeus Gas Pipeline .....  | 1   |
| Table 3.1 – NT Gas Pipeline licence relevant to covered pipeline .....   | 20  |
| Table 5.1 – Gas usage characteristics and drivers of demand and volumes at each delivery point.....                                  | 36  |
| Table 5.2 – Minimum, maximum and average demand and total volume by delivery point over the earlier access arrangement period.....   | 40  |
| Table 5.3 – User numbers by delivery point over the earlier access arrangement period.....   | 43  |
| Table 5.4 – Pipeline capacity and utilisation over the earlier access arrangement period.....  | 43  |
| Table 5.5 – Forecast minimum, maximum and average demand and total volume by delivery point over the access arrangement period ..... | 47  |
| Table 5.6 – Forecast user numbers by delivery point over the access arrangement period.....  | 57  |
| Table 5.7 – Forecast pipeline capacity and utilisation over the access arrangement period.....                                       | 59  |
| Table 6.1 – Asset classes .....  | 80  |
| Table 6.2 – Comparison of ACCC 2002 Final Decision and outturn capital expenditure over the earlier access arrangement period.....   | 81  |
| Table 6.3 – Capital expenditure by asset class over the earlier access arrangement period.....                                       | 82  |
| Table 6.4 – Forecast capital expenditure over the access arrangement period .....  | 83  |
| Table 6.5 – Forecast capital expenditure by asset class.....   | 89  |
| Table 7.1 – Forecast capital expenditure.....  | 93  |
| Table 7.2 – Remaining Economic Lives.....  | 94  |
| Table 7.3 – Forecast straight line depreciation over the access arrangement period.....  | 95  |
| Table 7.4 – Forecast indexation of the capital base.....   | 95  |
| Table 7.5 – Projected capital base for the access arrangement period.....  | 96  |
| Table 7.6 - Disaggregation of ACCC 2002 Final Decision forecast depreciation.....  | 98  |
| Table 7.7 – Outturn CPI .....  | 98  |
| Table 7.8 – Indexation of the Capital Base 2002-2011 .....   | 98  |
| Table 7.9 – Tax Asset Base as at 30 June 2011 .....  | 99  |
| Table 7.10 – Opening capital base for the access arrangement period .....  | 99  |
| Table 8.1 – Studies that can be referenced in valuing theta .....  | 114 |
| Table 8.2 – WACC estimate .....  | 115 |



|   |     |
|---|-----|
| Table 9.1 – Summary table of base year adjustments and step changes .....   | 127 |
| Table 9.2 – Total forecast operations and maintenance expenditure in the access arrangement period .....  | 128 |
| Table 9.3 – Total forecast overheads expenditure in the access arrangement period .....   | 133 |
| Table 9.4 – Total forecast sales and marketing expenditure in the access arrangement period .....   | 134 |
| Table 9.5 – Forecast operating expenditure over the access arrangement .....  | 134 |
| Table 9.6 – Comparison of ACCC 2002 Final Decision and actual and forecast operating expenditure over the earlier access arrangement period ..... | 140 |
| Table 10.1 – Return on capital .....  | 141 |
| Table 10.2 – Forecast depreciation over the access arrangement period .....   | 141 |
| Table 10.3 – Corporate income tax allowance .....   | 142 |
| Table 10.4 – Total revenue requirement .....  | 142 |
| Table 11.1 – Forecast revenue requirement over the access arrangement period .....  | 145 |
| Table 11.2 – Smoothed revenue requirement .....   | 148 |
| Table 11.3 – X Factors .....  | 148 |



## List of figures

|  |     |
|--|-----|
| Figure 1.1 – Map of the Northern Territory Pipeline Network.....   | 2   |
| Figure 1.2 – NT Gas pipeline schematic.....  | 3   |
| Figure 1.3 – APA Group Structure - Amadeus Gas Pipeline.....   | 5   |
| Figure 5.1 – Total gas demand over the earlier access arrangement period by delivery point.....  | 34  |
| Figure 5.2 – Total gas and substitute demand over the earlier access arrangement period.....   | 34  |
| Figure 5.3 – Daily volumes over the earlier access arrangement period against pipeline capacity .....  | 38  |
| Figure 5.4 – Actual and forecast total gas demand over the access arrangement period.....  | 46  |
| Figure 5.5 – Alice Springs delivery point volume forecast.....   | 50  |
| Figure 5.6 – Tennant Creek delivery point volume forecast.....   | 50  |
| Figure 5.7 – Daly Waters delivery point volume forecast .....  | 51  |
| Figure 5.8 – Mataranka delivery point volume forecast.....   | 52  |
| Figure 5.9 – Darwin/Katherine transmission system seasonal demand profile.....   | 53  |
| Figure 5.10 – Forecast gas demand for the Darwin/Katherine transmission system by delivery point.....  | 56  |
| Figure 6.1 – Comparison between forecast and actual capital expenditure over the earlier access arrangement period .....                             | 63  |
| Figure 6.2 – Replacement capital expenditure comparison to forecast over the earlier access arrangement period.....                                  | 65  |
| Figure 6.3 – Non-system capital expenditure comparison to forecast over the earlier access arrangement period.....                                   | 79  |
| Figure 6.4 – Capital expenditure trend over the earlier access arrangement period and access arrangement period .....                                | 84  |
| Figure 6.5 – Forecast capital expenditure over the access arrangement period .....   | 84  |
| Figure 9.1 – Total operating expenditure comparison to forecast over the earlier access arrangement period.....                                      | 118 |
| Figure 9.2 – Sales and marketing operating expenditure comparison to forecast over the earlier access arrangement period .....                       | 122 |
| Figure 9.3 – Adjusted base year 2009/10 operating and maintenance expenditure compared to other years in the earlier access arrangement period ..... | 124 |
| Figure 9.4 – Operating expenditure over the earlier access arrangement period and access arrangement period.....                                     | 134 |



|   |     |
|---|-----|
| Figure 9.5 – Forecast operating expenditure by category over the access arrangement period..... | 135 |
| Figure 9.6 – Operating expenditure per kilometre.....   | 138 |
| Figure 9.7 – Operating expenditure per mmkm .....   | 138 |





## List of boxes

|   |    |
|---|----|
| Box 6.1 – Katherine Meter Station Upgrade .....                       | 64 |
| Box 6.2 – Channel Island meter replacement .....                      | 69 |
| Box 6.3 – Channel Island piggability project .....                    | 70 |
| Box 6.4 – Replacement of Elliott heaters .....                        | 71 |
| Box 6.5 – Southbound piggability project .....                        | 71 |
| Box 6.6 – Cathodic protection upgrade – Stage 2 .....                 | 72 |
| Box 6.7 – Hazardous areas assessments and equipment replacement ..... | 74 |
| Box 6.8 – Palm Valley filtration and slam-shut installation .....     | 75 |
| Box 6.9 – Heat shrink sleeve replacement project .....                | 75 |
| Box 6.10 – Below ground station pipework recoating .....              | 77 |





## Executive Summary

NT Gas Pty Limited (NT Gas) is required to submit proposed revisions to the full access arrangement applying to the Amadeus Gas Pipeline (AGP) by 1 January 2011.

The AGP consists of the mainline or system backbone and comprises four gas inlet stations (Palm Valley, Mereenie, Ban Ban Springs and Weddell), a compressor station (Warrego), one odorant station (Tylers Pass), eleven mainline valves, eleven scraper stations and thirteen offtakes. The AGP is approximately 1 658 kilometres in length, including the Mereenie spurline, Tennant Creek and Katherine laterals, and the Pine Creek outlet.

This submission provides supporting information for NT Gas' proposed revision of the access arrangement for the AGP to apply for five years from 1 July 2011. This submission accompanies NT Gas' proposed revised access and arrangement access arrangement information, and should be read in conjunction with those documents. This document also addresses relevant requirements of the Regulatory Information Notice under the National Gas Law (NGL) served on NT Gas by the Australian Energy Regulator on 19 November 2010.

### Context for the review

#### *Enhanced integrity works*

Recent integrity surveys have uncovered significant integrity issues with the pipeline that NT Gas considers, based on risk assessment, require immediate rectification. These integrity issues largely reflect the age of the pipeline (which is now at mid life) and the harsh environment in which it is situated.

An enhanced integrity works program has been established to address these integrity issues and to establish an appropriate basis for enhanced monitoring and maintenance of the pipeline as the pipeline ages. The program begins in 2010/11 and impacts both capital and operating expenditure in the access arrangement period.

#### *Change in the operation of the pipeline*

Declining reserves in the Amadeus Basin in the earlier access arrangement period led Power and Water Corporation (PWC), the principal user of the pipeline, to develop a new gas supplies from the Blacktip gas field. Gas from this field now enters the AGP at Ban Ban Springs. As a result, the predominant direction of gas flow on the pipeline has changed to a net southbound flow south of Ban Ban Springs.

NT Gas has reviewed its Transportation (Firm) and Interruptible services in place in the earlier access arrangement period, clarifying that they are 'any direction' services. The tariff structure has also been changed from that in place in the earlier access arrangement period to ensure that NT Gas can recover its efficient costs in



delivering pipeline services to customers along the length of the pipeline, and to ensure that tariffs to all customers are appropriate and in line with expectations.

## Demand

Total gas demand on the AGP is expected to grow by 2.2 per cent per year over the access arrangement period. This forecast has been derived from the combined forecast of each delivery point on the pipeline, taking account of the specific demand characteristics of each delivery point.

Pipeline capacity increased with the connection of the Bonaparte Gas Pipeline and change in the flow of gas on the pipeline. Pipeline capacity is now expected to be 104TJ/day (notional value). Utilisation of capacity over the period is expected to grow from 79 per cent in 2010/11 to 86 per cent in 2015/16, while at the same time the full capacity of the pipeline is expected to be contracted to the current single user of the pipeline.

## Building block revenue proposal

NT Gas' forecast capital and operating expenditure over the access arrangement period are set out in Table 0.1 and in chapter 6 and chapter 9 of this submission.

**Table 0.1 – Forecast capital and operating expenditures over the access arrangement period**

| \$ '000 (2009/10)     | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | Total         |
|-----------------------|---------|---------|---------|---------|---------|---------------|
| Capital expenditure   | 8,506   | 1,473   | 1,509   | 1,185   | 1,385   | <b>14,058</b> |
| Operating expenditure | 13,152  | 14,853  | 13,419  | 13,514  | 16,229  | <b>71,165</b> |

Forecast **capital expenditure** for the access arrangement period is \$14.1 million. This expenditure includes non-routine expenditure in 2011/12 associated with the enhanced integrity program, as well as ongoing routine expenditure.

NT Gas does not forecast any expansion capital expenditure in the access arrangement period.

Replacement capital expenditure – relating to the renewal and replacement of ageing pipeline assets, asset condition, and compliance requirements for safety, reliability and asset protection – is forecast to be \$13.0 million. This expenditure includes required integrity works and upgrades to the Cathodic Protection system in place for the pipeline.

Non-system capital expenditure – relating to capital required for replacement of items such as office furniture and computer equipment – is forecast to remain in line with expenditure in the earlier access arrangement period. NT Gas forecast expenditure in this category to be \$1.0 million over the access arrangement period.



Total forecast **operating expenditure** for the access arrangement period is \$71.2 million. This value represents an increase compared to the earlier access arrangement period due mainly to step changes in costs associated with enhanced integrity works, increased scope of operations, and changes in technical requirements.

NT Gas' corporate overheads expenditure is expected to increase compared to the earlier access arrangement period. This arises from the full allocation of corporate overhead costs to NT Gas in the access arrangement period, where in the earlier period the full corporate cost allocation was not recovered from NT Gas and was instead incurred at a corporate level.

Other elements of the building blocks proposal include:

- A nominal vanilla weighted average cost of capital of 11.42 per cent based on current market parameters;
- A capital base rolled forward in accordance with the roll forward model provided at Attachment E, yielding an opening capital base for the access arrangement period of \$112.4 million;
- A tax asset base (TAB) derived using the opening TAB in the earlier access arrangement period, and rolling it forward using the actual capital expenditure; and
- Depreciation calculated by applying the remaining economic life of assets over the opening capital base value as at 1 July 2011, and forecast expenditure using straight line depreciation.

## Revenue requirement

NT Gas proposed revenue requirement and X-factors are shown in Table 0.2. The revenue requirement is translated into a price path in a CPI-X format. X-factors set at zero translate into tariff changes by CPI only over the access arrangement period.

**Table 0.2 – Forecast revenue requirement and X-factors**

| \$ '000 (2009/10)                      | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|--|---------|---------|---------|---------|---------|
| AGP Building block revenue requirement | 33,090  | 34,948  | 34,036  | 34,570  | 33,189  |
| Smoothed revenue requirement           | 32,481  | 33,293  | 34,125  | 34,978  | 35,853  |
| X Factors                              | NA      | 0       | 0       | 0       | 0       |

NT Gas proposes a firm transportation capacity service as the reference service. The reference tariff is incorporated in the access arrangement.





## Abbreviations

|       |  |
|-------|--|
| ABDP  | Amadeus Basin to Darwin Pipeline               |
| ABS   | Australian Bureau of Statistics                |
| ACCC  | Australian Competition and Consumer Commission |
| ACN   | Australian Company Number                      |
| ACT   | Australian Capital Territory                   |
| AEMO  | Australian Energy Market Operator              |
| AER   | Australian Energy Regulator                    |
| AGL   | Australian Gas Light Pty Limited               |
| AGP   | Amadeus Gas Pipeline                           |
| AMP   | Asset Management Plan                          |
| APIA  | Australian Pipeline Industry Association       |
| AS    | Australian Standard                            |
| CAPM  | Capital Asset Pricing Model                    |
| CGS   | Commonwealth Government Securities             |
| CP    | Cathodic Protection                            |
| CPI   | Consumer Price Index                           |
| Cth   | Commonwealth                                   |
| DCVG  | Direct Current Voltage Gradient                |
| DRP   | Debt Risk Premium                              |
| GIS   | Geographic Information System                  |
| HAZOP | Hazard and Operability                         |
| HSE   | Health, Safety and Environment                 |
| ICB   | Initial Capital Base                           |
| IP    | Intelligent Pigging                            |



|       |  |
|-------|--|
| IT    | Information Technology                   |
| km    | kilometre                                |
| LNG   | Liquefied Natural Gas                    |
| MAOP  | Maximum Allowable Operating Pressure     |
| MDQ   | Maximum Daily Quantity                   |
| mm    | millimetre                               |
| MRP   | Market Risk Premium                      |
| Mt    | Mount                                    |
| NGL   | National Gas Law                         |
| NGR   | National Gas Rules                       |
| NT    | Northern Territory                       |
| ORC   | Optimised Replacement Cost               |
| PMP   | Pipeline Management Plan                 |
| PTRM  | Post Tax Revenue Model                   |
| PWC   | Power Water Corporation                  |
| RIN   | Regulatory Information Notice            |
| ROW   | Right of Way                             |
| SA    | South Australia                          |
| SCADA | Supervisory Control and Data Acquisition |
| TAB   | Tax Asset Base                           |
| TJ    | Terajoule                                |
| UAG   | Unaccounted for Gas                      |
| WACC  | Weighted Average Cost of Capital         |





# 1 Introduction

## 1.1 Purpose of this submission

This submission provides supporting information for N.T. Gas Pty Limited's (NT Gas') proposed revision of the Access Arrangement for the Amadeus Gas Pipeline (AGP)<sup>1</sup> from 1 July 2011.

In accordance with the requirements of section 132 of the National Gas Law (NGL) and section 43(1) of the National Gas Rules (NGR)<sup>2</sup>, NT Gas has provided to the Australian Energy Regulator (AER) with this submission:

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

Together these documents make NT Gas' access arrangement revision proposal.

## 1.2 Layout of this submission

Subsequent sections and chapters of this submission incorporate detailed information supporting the access arrangement proposal and access arrangement information, set out as follows:

- The remainder of this Chapter 1 outlines the history of the pipeline and describes the operations of the service provider and context for the access arrangement revision proposal;
- Chapter 2 specifies the services offered and non-price terms and conditions under the access arrangement;
- Chapter 3 discusses key regulatory instruments and obligations, including new and changed regulatory obligations impacting demand and cost forecasts;
- Chapter 4 provides an overview of NT Gas' long-term strategy, planning and governance processes and documents;
- Chapter 5 discusses pipeline demand and utilisation during the earlier access arrangement period and forecast demand over the access arrangement period;

---

<sup>1</sup> Formerly referred to as the Amadeus Basin to Darwin Gas Pipeline, and revised for this access arrangement to the Amadeus Gas Pipeline, to reflect the change in use of the pipeline since the earlier access arrangement, as discussed in section 1.5.4 of this submission.

<sup>2</sup> Hereinafter, a reference to a Rule shall, unless otherwise specified, be understood to refer to a Rule of the *National Gas Rules 2008 version 6*.



- Chapter 6 sets out capital expenditure undertaken and to be undertaken during the earlier access arrangement period and the justification and forecast cost of capital projects during the access arrangement period;
- Chapter 7 outlines the derivation of the opening capital base of the AGP from which a return on and of capital are calculated;
- Chapter 8 explains the parameters of the capital asset pricing model proposed for calculation of the weighted average cost of capital for the rate of return during the access arrangement period;
- Chapter 9 explains the derivation of operating and maintenance costs;
- Chapter 10 calculates the total revenue to be derived from the pipeline;
- Chapter 11 explains the basis and derivation of the reference tariff, including cost allocation and tariff variation mechanisms; and
- Attachments contain explanatory and supporting material required by the RIN or referred to in the text.

## 1.3 Requirements for access arrangement revision proposal

### 1.3.1 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.<sup>3</sup> 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.<sup>4</sup> 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 AGP since the earlier access arrangement falls under these provisions within the definition of a *transitional access arrangement*.

---

<sup>3</sup> In NT, this is under section 7 of the *National Gas (Northern Territory) Act 2008* (NT), which applies the National Gas Law set out in the schedule to the *National Gas (South Australia) Act 2008* (SA) as the law in the NT and as so applying may be referred to as the *National Gas (NT) Law*.

<sup>4</sup> NGL, schedule 3, sections 6 and 7



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”.<sup>5</sup>

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.<sup>6</sup>

NT Gas 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. NT Gas has also provided an Index at Attachment A of this submission which includes guidance on where requirements under the Rules can be found in the revision proposal.

### 1.3.2 Information required by Regulatory Information Notice

On 19 November 2010, the AER served on NT Gas 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 NT Gas in its access arrangement revision proposal, and the form of that information.

This submission, along with the access arrangement proposal and access arrangement information, provides information in satisfaction of the requirements placed on NT Gas in the RIN.

The RIN also requires that NT Gas 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 Attachment A to this submission.

### 1.3.3 Basis of information in the access arrangement revision proposal

Rule 73 states that:

- (a) Financial information must be provided on:
  - (i) a nominal basis

---

<sup>5</sup> NGL, Schedule 3, section 3

<sup>6</sup> 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.



- (ii) a real basis
- (iii) some other recognised basis for dealing with the effects of inflation.
- (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 2009/10 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).

Forecast inflation for the access arrangement period for the financial modelling is forecast as discussed in section 8.9 of this submission.

Units used in the access arrangement revision proposal are noted throughout and described in the abbreviation list at page xiii of this submission.

The access arrangement revision proposal uses the convention established in the NGR of referring to the *access arrangement period*, being for the AGP the period in which the revised access arrangement will apply (proposed to be the period between 1 July 2011 and 30 June 2016), and the *earlier access arrangement period*, being the period 1 July 2001 to 30 June 2011.

## 1.4 Pipeline construction, ownership and regulatory history

### 1.4.1 Development and construction of the pipeline

In the mid 1960s natural gas was discovered at the Amadeus Basin, near Alice Springs, in both the Palm Valley and Mereenie fields. These discoveries, while significant, remained undeveloped due to the inaccessibility of markets for such remote reserves. In September 1983 gas for base load electricity generation was first produced and delivered to PWC<sup>7</sup> at Alice Springs, 150 kilometres from the Palm Valley gas field<sup>8</sup>.

In 1984 the Northern Territory (NT) Government began construction of a new coal fired power station on Channel Island some 42 kilometres from the city of Darwin. During the course of constructing the power station, the NT Government, after conducting a feasibility study of the gas reserves in the Amadeus Basin and assessing the economics of hauling natural gas to Darwin via pipeline, committed both the Channel Island and Katherine power stations to be fuelled by natural gas.

---

<sup>7</sup> Then known as the Northern Territory Electricity Commission

<sup>8</sup> Gas is delivered to Alice Springs through the Palm Valley to Alice Springs Pipeline, which is owned by Envestra Limited.



NT Gas was formed from a consortium of companies to finance, construct, commission and operate the then called Amadeus Basin to Darwin Pipeline (ABDP). The pipeline was commissioned in December 1986 and first gas delivered to the PWC in January 1987.

Between the commissioning of the AGP and the start of the earlier access arrangement period (July 2001) a number of lateral pipelines were constructed to interconnect with the AGP<sup>9</sup>, including the:

- Cosmo Howley pipeline which was commissioned in 1988 and gas supplied to fuel the power station at the Cosmo Howley mine. In 2004/05 the power station ceased electricity generation. The Cosmo Howley pipeline was decommissioned in 2008;
- Elliott pipeline, which was commissioned in 1989 and gas supplied to fuel the power station at the Elliott township;
- Manton pipeline, which was commissioned in 1989 and gas supplied to fuel the temporary power station at Manton. The power station ceased electricity generation before the start of the earlier access arrangement period and no gas has flowed to this delivery point during the earlier period. The Manton pipeline is currently undergoing decommissioning;
- McArthur River pipeline, which was commissioned in February 1995 and gas was supplied to fuel the power station at the McArthur River mine;
- Darwin City Gate to Berrimah pipeline, which was commissioned and gas supplied to commercial and industrial users in the Darwin environs in January 1996; and
- Mt Todd pipeline, which was commissioned in October 1996 and gas supplied to fuel the power station at the Mount Todd mine. In November 1997 mining operations were suspended at the mine after the mine owner Pegasus Gold Australia Pty Limited became insolvent forcing the pipeline infrastructure out of service. For a short period early in the earlier access arrangement period the pipeline was used for electricity generation fed into the Darwin/Katherine grid. The Mt Todd lateral is now idle.

Over the earlier access arrangement period, a major new supply point was added to the pipeline at Ban Ban Springs (commissioned in 2008). A new delivery point, which when needed can also operate as a secondary supply point, was also commissioned in 2007 at Weddell.

#### 1.4.2 Ownership history of the pipeline

Ownership of the AGP is vested in a consortium of banks and the pipeline is leased to NT Gas as trustee of the Amadeus Gas Trust. The provisions of the Trust Deed

---

<sup>9</sup> Not all of these pipelines form part of the AGP for the purposes of this access arrangement.



specify the manner in which revenue received from the operation of the AGP is to be distributed to beneficiaries under the Trust who include the shareholders of NT Gas.

In 1988 the AGL Group acquired through wholly owned subsidiaries<sup>10</sup> 96 per cent of NT Gas, the other shareholders being Darnor Pty Limited (an NT Government company) 2.5 per cent and Centrecorp Aboriginal Investment Corporation Pty Limited (a company owned by the Central Land Council) 1.5 per cent. In June 2000, AGL floated its pipeline interests, including its share of NT Gas, through a transfer to the Australian Pipeline Trust.

### 1.4.3 Coverage and regulatory background of the pipeline

#### *Regulatory history*

In 1998, the relevant Commonwealth minister certified the *National Third Party Access Code for Natural Gas Pipeline Systems* (the National Gas Code) as an effective access regime for the state of South Australia (SA) under section 44N of the *Trade Practices Act 1974* (Cth), effective for 15 years. The National Gas Code was made law in SA under the *Gas Pipeline Access (South Australia) Act 1997* (SA) and formed schedule 2 to that Act.

The National Gas Code was given application in the NT under the *Gas Pipeline Access (Northern Territory) Act 1998* (NT) and was separately certified for the NT by the relevant Commonwealth minister in October 2001 (effective for 15 years). The AGP was included in a schedule to the National Gas Code listing pipelines and networks covered from the commencement of the Code.

On 26 March 2003, the then regulator for gas transmission pipelines under the National Gas Code (other than in Western Australia), the Australian Competition and Consumer Commission (ACCC), approved the access arrangement to apply to the AGP for the period 1 July 2001 to 30 June 2011. The Access Arrangement established an Initial Capital Base of \$228.5 million (\$nominal) as at 1 July 2001, and approved accelerated depreciation for the pipeline over the access arrangement period to the residual value of the leased pipeline assets of \$61.84 million (\$nominal) in 2011. A zonal reference tariff was approved based on three zones as follows:

- Zone 1 – Palm Valley to Warrego
- Zone 2 – Warrego to Mataranka
- Zone 3 – Mataranka to Channel Island

The access arrangement required NT Gas to submit revisions to the access arrangement by 1 January 2011.

The earlier access arrangement also included two trigger events whereby if one or both occurred, the regulator could notify NT Gas, requiring NT Gas to submit revisions to the access arrangement prior to 1 January 2011. These triggers were:

---

<sup>10</sup> Agex Pty Limited and Sopic Pty Limited



- The interconnection of another pipeline with the Pipeline; or
- The introduction of a significant new source of gas supply to one or more of the markets to which gas is delivered from the pipeline;

that substantially changes the types of services that are likely to be sought by the market or has a substantial effect on the direction of flow of natural gas through all or part of the pipeline.<sup>11</sup>

In July 2007, the ACCC undertook a review of whether a trigger event had occurred for the AGP, and sought submissions from interested parties on the matter, including from NT Gas, PWC and the NT Government Treasury.<sup>12</sup> At the time, the ACCC concluded that there had not been a trigger event on the pipeline, but did note that “a trigger event is likely to occur in the future, in particular the interconnection of the Bonaparte Gas Pipeline to transport gas from the Blacktip field in the Bonaparte Basin”<sup>13</sup>.

When the Bonaparte Gas Pipeline, interconnecting with the AGP, was commissioned in 2008 the ACCC did not notify, nor has the AER since notified, NT Gas of a trigger event bringing forward the revisions submission date. NT Gas therefore submits its access arrangement revision proposal, of which this submission is part, in compliance with its obligations under the earlier access arrangement to submit revisions to the access arrangement no later than 1 January 2011.

## **1.5 Pipeline overview and context for the access arrangement revision proposal**

### **1.5.1 Pipeline system characteristics**

The pipeline system consists of the mainline or system backbone and comprises four gas inlet stations (Palm Valley, Mereenie, Ban Ban Springs and Weddell), a compressor station (Warrego), one odorant station (Tylers Pass), eleven mainline valves, eleven scraper stations and thirteen offtakes. The AGP is approximately 1,629 kilometres in length, including the Mereenie spurline, Tennant Creek and Katherine laterals, and the Pine Creek outlet.

#### *Supply points*

The Palm Valley Joint Venture supplies the gas received at the Palm Valley inlet station from their gas treatment plant, while the Mereenie Joint Venture supplied gas received at the Mereenie inlet station from their gas treatment plant. Since April 2010, no gas has been injected from the Mereenie gas field into the pipeline. An odorant plant is located at Tylers Pass where the Mereenie spurline joins the AGP.

---

<sup>11</sup> NT Gas Pty Limited 2003, *Access Arrangement for Amadeus Basin to Darwin Pipeline*, February, section 9.2

<sup>12</sup> ACCC 2007, *ADBP access arrangement – review of trigger mechanisms*, July, p 2

<sup>13</sup> ACCC 2007, *Review of trigger mechanism: Amadeus Basin to Darwin Pipeline*, September, p 1





The Weddell delivery point supplies gas to the Weddell Power Station near Darwin. The commissioning of the Wickham Point Spurline in 2009<sup>14</sup>, connecting the Conoco Phillips Darwin Liquefied Natural Gas (LNG) facility with the Weddell lateral, means that this delivery point can operate as emergency supply to the AGP if required, with gas coming from the Bayu Undan gas fields.

The Bonaparte Gas Pipeline<sup>15</sup> joins the AGP at Ban Ban Springs, bringing gas supplied by Eni Australia B.V. from the Blacktip gas field. Gas is received at the Ban Ban Springs inlet station from the onshore processing plant at Wadeye via the Bonaparte Gas Pipeline. Gas started to be supplied into the AGP at the Ban Ban Springs supply point in 2009.<sup>16</sup>

### *Delivery Points and laterals*

The AGP has thirteen delivery points along its length that received gas during the earlier access arrangement period, connected to laterals serving various markets. The delivery points and laterals they service are set out in Table 1.1 over the page.

### *Operation of the pipeline*

Operation of the pipeline system is continuously monitored and controlled during business hours from a control centre located in Palmerston approximately 20 kilometres south of the Darwin central business district, and outside business hours from the APA Group control centre located in Young, New South Wales.

The AGP was initially constructed with no compressor stations and could transport a maximum of 44 TJ/day. Initial parameters for the AGP made provision for an additional nine compressor stations to be constructed as natural gas demand increased. In 1995, a compressor station at Warrego (40 kilometres north of Tennant Creek) was commissioned. The compressor station increases nominal capacity to 55 TJ/day. The connection of the Bonaparte Gas Pipeline has further increased the capacity of the pipeline, discussed further in section 5.1.3.

A pipeline map can be found at Figure 1.1 and pipeline schematic at Figure 1.2 over the page.

---

<sup>14</sup> The Wickham Point spurline and Weddell lateral are not part of the covered pipeline.

<sup>15</sup> The Bonaparte Gas Pipeline is not part of the covered pipeline.

<sup>16</sup> Initial gas supply from the Bonaparte Gas Pipeline was the subject of special arrangements as the gas did not meet gas specifications. NT Gas reached a supply agreement with PWC to receive the off specification gas (called 'early gas') into the AGP on condition that PWC would fund required integrity survey and potential reparative works associated with the gas. The early gas period has ended and survey work on the pipeline required under the supply contract is currently underway.





**Table 1.1 – Delivery points and laterals along the Amadeus Gas Pipeline**

| Delivery point   | Lateral/Pipeline  | Additional details                              |
|------------------|---|---|
| Alice Springs    | Interconnect station to supply the Palm Valley to Alice Springs Lateral Pipeline* |   |
| Tennant Creek    | Tennant Creek Lateral Pipeline  |   |
| Elliott          | Elliott Lateral Pipeline*   |   |
| Daly Waters      | McArthur River Mine Lateral Pipeline*   |   |
| Mataranka        | Mataranka Lateral Pipeline*   | Low pressure plastic                            |
| Katherine        | Katherine Lateral Pipeline  |   |
| Mt Todd          | Mount Todd Lateral Pipeline*  | Suspended                                       |
| Pine Creek       | Pine Creek meter station  |   |
| Cosmo Howley     | Cosmo Howley Lateral Pipeline*  | Decommissioned in 2008                          |
| Ban Ban Springs  | Bonaparte Gas Pipeline*   | Commissioned in 2008                            |
| Darwin City Gate | Darwin Distribution System*   | High pressure steel and medium pressure plastic |
| Weddell          | Weddell and Wickham Point Lateral Pipelines*                                      | Commissioned in 2007                            |
| Channel Island   | Channel Island Lateral Pipeline   |   |

\*Laterals/pipelines that do not form part of the covered pipeline

## 1.5.2 Operating environment

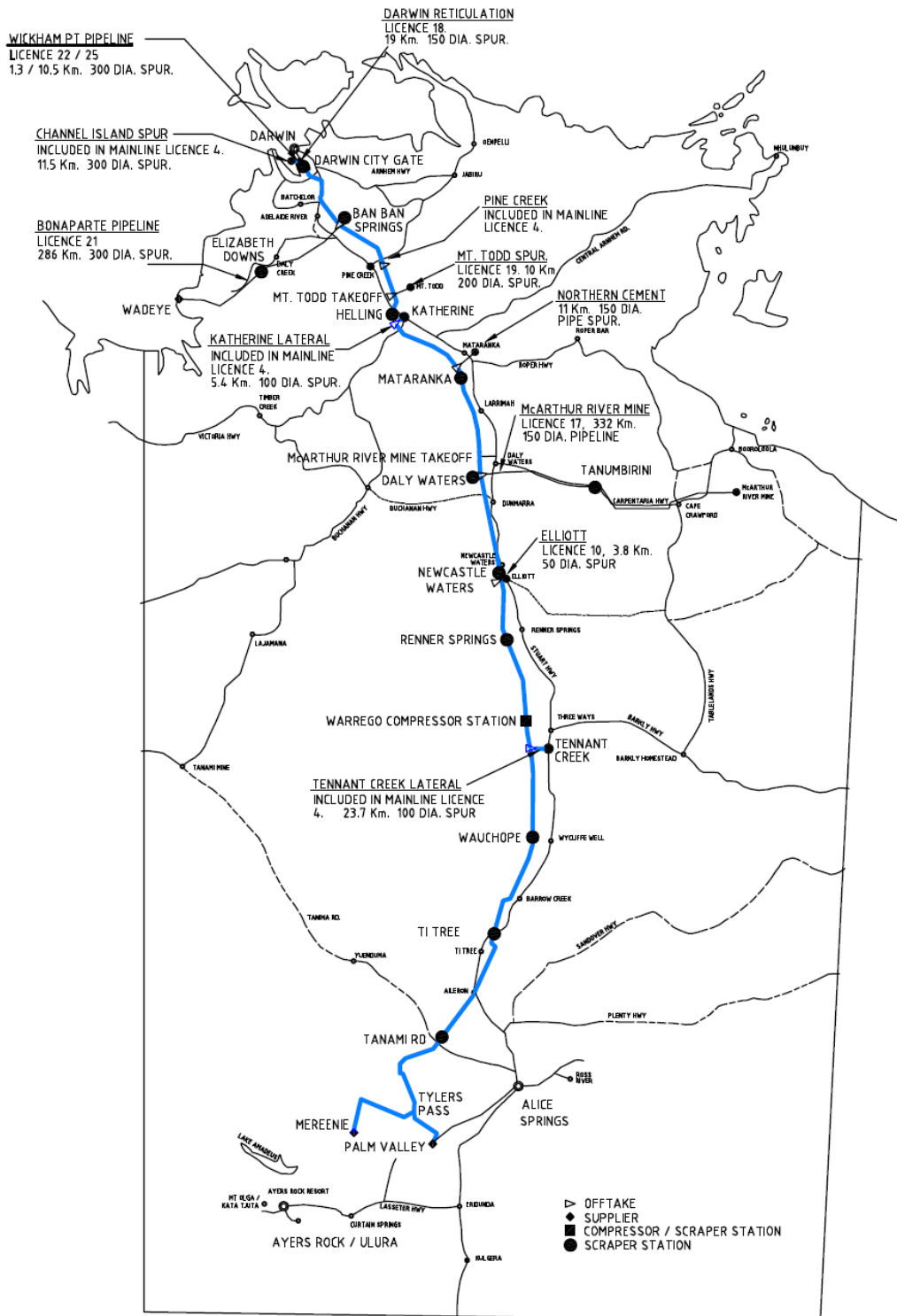
The AGP's operating environment is unique for pipelines operating in Australia, and poses particular challenges for NT Gas in ensuring the ongoing integrity of the pipeline and provision of pipeline services.

The AGP spans arid (in the south) and tropical (in the north) climates, characterised by climatic extremes brought about by the wet and dry seasons. NT Gas' annual expenditure profile is highly seasonal and concentrated in the dry season, reflecting the limitations that the wet season places on works on the pipeline. In the wet season, parts of the pipeline become inaccessible by any means other than helicopter, and travel to other parts of the pipeline becomes difficult and unreliable.

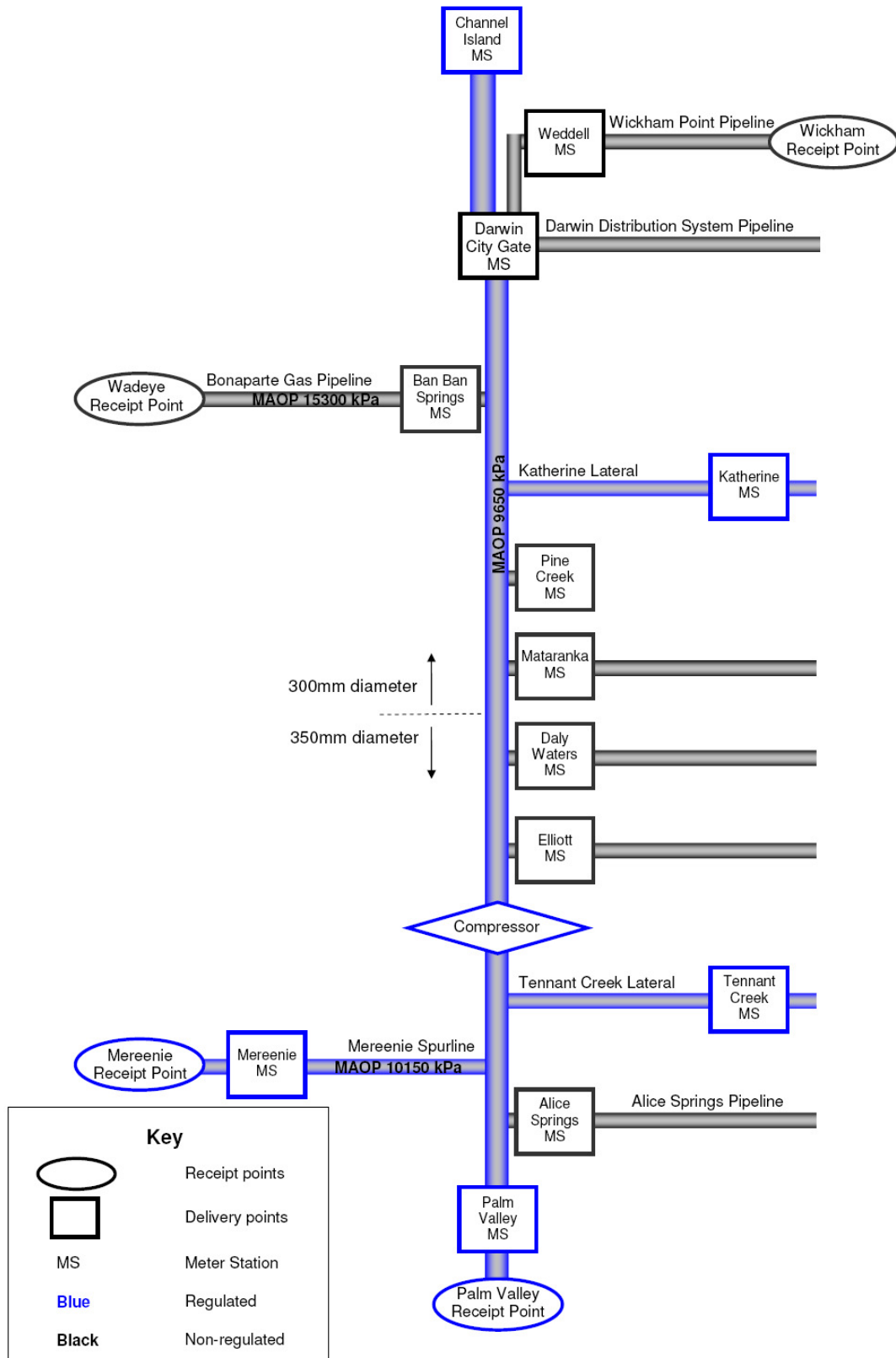
These factors impact NT Gas' operating costs as travel requires special equipment, such as four wheel drives and helicopters, and restrictions in travel movements for work crews, such as dusk to dawn travel curfews due to the dangers of travel on outback roads in the early evening and at night due to kangaroos and cattle on the road.



**Figure 1.1 – Map of the Northern Territory Pipeline Network**



**Figure 1.2 – NT Gas pipeline schematic**





The AGP is also extremely remote, which adds to the challenges of working on the pipeline. Work crews working in remote locations stay in local accommodation, which can be many kilometres from the pipeline. Night time travel restrictions can significantly curtail available work hours, adding to the time and costs of even routine work on the pipeline. The same remoteness makes the logistics of getting supplies and equipment to site very challenging, particularly in the wet season where roads, tracks and easements may be impassable.

Work crews working at remote sites are also a long way from medical assistance, and the dangers of working in extreme heat and sun limit working hours further to ensure health and safety.

The AGP spans earthquake prone areas, which means that sections of the pipeline must be inspected on a regular basis to ensure there has not been damage to the pipeline from tremors.

These factors mean that NT Gas' operations differ significantly from those of operators of other urban or rural pipelines, making meaningful comparison in the scope of work and costs very difficult. These factors mainly impact pipeline capital and operating costs, but non-system capital and operation expenditure is also plagued by logistical and supply issues, shortages in specialist and technical staff and contractors, and general staffing and recruitment issues associated with a remote location.

### 1.5.3 Overview of operations of the service provider

N.T. Gas Pty Limited ACN 050 221 415 is a legal entity registered under the *Corporations Act 2001* of the Commonwealth. The ownership of NT Gas comprises four corporate entities:

- 64 per cent owned by Agex Pty Ltd
- 32 per cent owned by Sopic Pty Ltd
- 2.5 per cent owned by Darnor Pty Limited
- 1.5 per cent owned by Centrecorp Aboriginal Investment Corporation Pty Ltd

Both Agex and Sopic are 100 per cent owned by the APA Group. Darnor is 100 per cent owned by PWC.

ANZ Leasing, a consortium of financial institutions owns the AGP. NT Gas is trustee of the Amadeus Gas Trust, and leases the AGP from ANZ Leasing until 2011 under a leveraged lease arrangement. NT Gas is also the licensee and operator of the AGP. APA Group provides the labour resources under an employment service agreement.

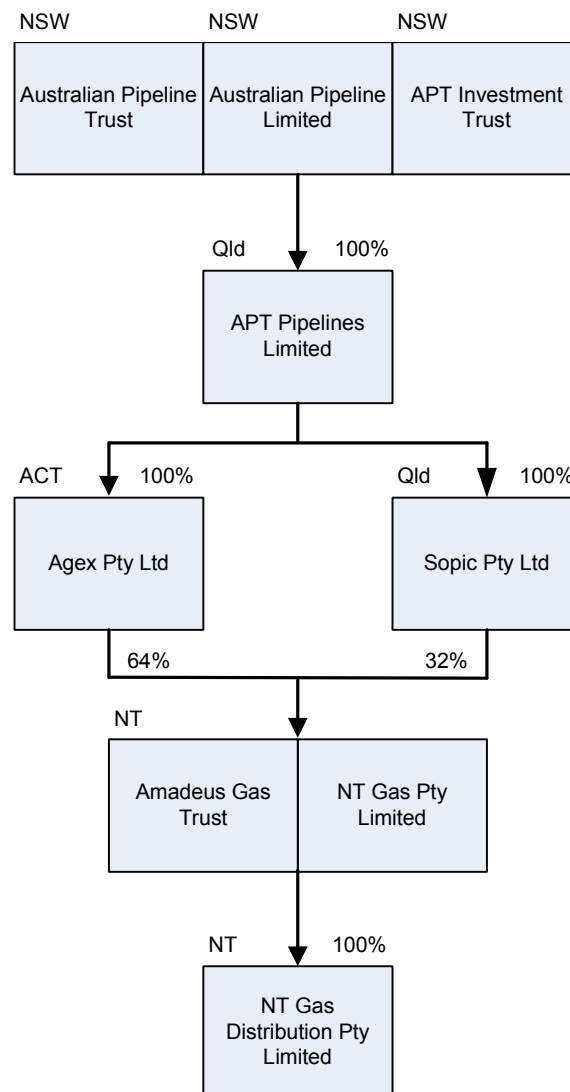
NT Gas is not a local agent of a service provider for the pipeline, nor is a service provider acting on behalf of other service providers.



Further details of the service provider and associates were provided to the AER in NT Gas' 2009-10 annual compliance report and these details have not changed and remain relevant for this access arrangement revision process.

The APA Group corporate structure relevant to the AGP is described in Figure 1.3 below.

**Figure 1.3 – APA Group Structure - Amadeus Gas Pipeline**



#### 1.5.4 Context for this access arrangement period

##### *Enhanced integrity works*

Recent integrity surveys of the pipeline (in particular intelligent pigging (IP) and direct current voltage gradient (DCVG) surveys) have uncovered significant integrity issues with the pipeline that NT Gas considers, based on risk assessment, require



immediate rectification. These integrity issues largely reflect the age of the pipeline, (which is now at mid life) and the harsh environment in which it is situated.

An enhanced integrity works program has been established to address these integrity issues and to establish an appropriate basis for enhanced monitoring and maintenance of the pipeline as the pipeline ages. This program is to be expected for a pipeline that has reached mid life, where more active management and monitoring of the integrity of the pipeline is required to ensure that the pipeline can remain in service and maintain its maximum allowable operating pressure (MAOP). Detailed studies of pipeline integrity in 2008 and 2009 have led NT Gas to establish a new integrity works program that is suitable for a pipeline of the age and condition of the AGP, consistent with NT Gas' risk management policy.

NT Gas' enhanced integrity program is to be delivered in two parts:

- a short term period of relatively high expenditure to address immediate integrity concerns, to be delivered through a special project delivery structure in 2010/11 and 2011/12; and
- longer term increased expenditure over that in the earlier access arrangement period, reflecting the new level of integrity expenditure required for this pipeline going forward.

NT Gas considers that the enhanced integrity works undertaken in the earlier access arrangement period and forecast for the coming period are necessary to ensure the ongoing integrity of the pipeline and the special project structure delivers efficiencies in project delivery that could not be accessed at another time or through works carried out over a longer period. Further details on this program of works are provided in chapters 6 and 9 related to capital and operating expenditure respectively.

### *Change in the operation of the pipeline*

Declining reserves in the Amadeus Basin in the earlier access arrangement period led PWC, the principal user of the pipeline, to seek to secure a new source of gas to meet its contractual load along the pipeline. The development of the new gas supply point at Ban Ban Springs connecting gas from the Blacktip gas field to the AGP, alongside a reduction in gas being injected into the AGP from the Amadeus Basin, has changed the predominant direction of flow of gas on the AGP to a southerly flow south of Ban Ban Springs. Gas demand is discussed further in chapter 5.

As a result, NT Gas has reviewed its Transportation and Interruptible services in place in the earlier access arrangement period, clarifying that they are 'any direction' services. NT Gas considers that this structure provides Users flexibility in how they use the pipeline and source gas, which NT Gas considers will assist in the development of the market through potential interruptible contracts, particularly in the southern end of the pipeline. Pipeline services for the access arrangement period are discussed further in chapter 2.



The tariff structure must also change from that in place in the earlier access arrangement period to ensure that NT Gas can recover its efficient costs in delivering pipeline services to customers along the length of the pipeline, and to ensure that tariffs to all customers are appropriate and in line with expectations. The tariff structure must also be consistent with the revised pipeline services under the access arrangement. Tariffs are discussed further in chapter 11.

The change in flow on the pipeline is also the driver of the change in the name of the pipeline from the Amadeus Basin to Darwin Pipeline to the Amadeus Gas Pipeline, as the predominant source of gas for the pipeline is no longer from the Amadeus Basin.







## 2 Services

The Rules require an access arrangement to:

- describe the pipeline services the service provider proposes to offer to provide by means of the pipeline<sup>17</sup>;
- specify the reference services<sup>18</sup>; and
- specify for each reference service<sup>19</sup>:
  - the reference tariff; and
  - the other terms and conditions on which the reference service will be provided.

This chapter describes the basis for proposing the services set out in the access arrangement, as well as proposed changes to non-tariff components in the access arrangement.

### 2.1 Pipeline services

A pipeline service is a service provided by means of the pipeline.<sup>20</sup> NT Gas proposes to offer the following services on the AGP:

- Firm service – service for transport from any receipt points to any delivery points on the pipeline;
- Interruptible service – service for transport from any receipt points to any delivery points on the pipeline, where NT Gas is entitled to cease receiving gas from, or delivering gas to, the user when pipeline capacity is constrained/curtailed, or to meet the capacity requirements of other users of the firm service;
- Negotiated service – service negotiated to meet the needs of a user which differ from those of the firm or interruptible service, including potential as available services.

The firm service offered is comparable to the transportation service included in the earlier access arrangement. The interruptible and negotiated services are comparable to those of the same name in the earlier access arrangement.

With the connection of the Bonaparte Gas Pipeline at Ban Ban Springs and the Wickham Point pipeline at Weddell, gas can now enter the pipeline at four different receipt points, and be delivered to ten active delivery points along the length of the

---

<sup>17</sup> Rule 48(1)(b)

<sup>18</sup> Rule 48(1)(c)

<sup>19</sup> Rule 48(1)(d)

<sup>20</sup> National Gas Law section 2



pipeline. This means that, at least notionally, gas can flow in any direction along the pipeline, and transportation agreements can imply either northbound or southbound flow depending on the location of receipt and delivery points specified in the agreement.

NT Gas has therefore revised the firm and interruptible services to make clear that gas transportation can be bidirectional, such that users and prospective users can nominate gas flows between any receipt and delivery point along the pipeline under these services.

NT Gas considers that these services represent the scope of available services on the AGP.

### 2.1.1 Reference services

Reference services are a subset of pipeline services, and are those pipeline services that are likely to be sought by a significant part of the market.<sup>21</sup>

NT Gas specifies the firm service as a reference service, as it considers that this service is sought by a significant part of the market. The firm service most closely corresponds with the service offered under the current foundation contract on the pipeline, which relates to 100 per cent of firm capacity available for contracting on the pipeline. Over the earlier access arrangement period, less than one per cent of gas was transported under arrangements outside of the foundation contract, despite the availability of interruptible and negotiated services in this time.

NT Gas further notes that under current contractual arrangements, the firm service is fully contracted and not available. It is also likely that under arrangements currently under negotiation, the firm reference service will remain fully contracted. Despite this, the increase in capacity of the pipeline in the access arrangement period (see section 5.1.3 below) means that some limited contracted but unutilised capacity may be available over the shorter term for a firm service transportation agreement with a different user, particularly south of Ban Ban Springs.

NT Gas considers that this potential firm capacity is likely to be preferentially sought by the majority of prospective users on the pipeline over the interruptible service. This means that the firm service is appropriately characterised as a reference service under the access arrangement.

### 2.1.2 Non-Reference services

NT Gas proposes to offer the interruptible service and the negotiated service as non-reference services in the access arrangement, consistent with the earlier access arrangement.

NT Gas considers that these services are appropriately classified as non-reference services as currently there are no transportation contracts in place for gas delivery on

---

<sup>21</sup> Rule 101(2)



the pipeline for either of these services and in total, interruptible and negotiated services represented less than one per cent of gas transported on the pipeline over the earlier access arrangement period. These services cannot therefore be considered to be sought by a significant part of the market and therefore are not appropriately classed as reference services.

To the extent that prospective users seek transportation services on the AGP during the access arrangement period, it is expected that those users will preferentially seek any available firm capacity on the pipeline before seeking an interruptible service. This reflects experience over the earlier access arrangement period where prospective users in the first instance generally sought a firm transportation agreement, and only took a limited interruptible service as the firm service was not available.

The interruptible service was specified as a rebateable service under the earlier access arrangement. Rebateable services are services that are not reference services, and for which substantial uncertainty exists concerning the extent of the demand for the service or of the revenue to be generated from the service. The Rules require that market for the rebateable service also be substantially different from the market for any reference services.<sup>22</sup>

NT Gas does not consider that the interruptible service satisfies the requirements under the Rules to be classed as a rebateable service. While there is considerable uncertainty over potential demand for the interruptible service, NT Gas does not consider that the market for this service is substantially different from that for the firm service. Prospective users of firm and interruptible services are generally the same – mining or industrial operators. As outlined above, these prospective users generally seek a firm service but are prepared to consider an interruptible service, suggesting that the market for the interruptible service (to the extent one exists) is not substantially different to that of the firm reference service.

NT Gas further considers that classifying the interruptible service as a rebateable service potentially adds unnecessary complexity to tariff arrangements for the pipeline, and may act as a disincentive for NT Gas to actively seek additional users of the pipeline. Designation as a rebateable service generally requires that a portion of revenue generated from the sale of rebateable services be provided as a rebate to the users of the reference service.

As the current sole user of the pipeline does not contract on the basis of the reference tariff, this type of mechanism has little meaning for the pipeline and adds unnecessary complexity to the access arrangement, as well as compliance costs.

NT Gas therefore proposes to offer the interruptible service and the negotiated service as non-reference services.

---

<sup>22</sup> Rule 93(4)



## 2.2 Non-tariff components

NT Gas has revised its access arrangement to apply in the access arrangement period. Key revisions made to the earlier access arrangement relate to:

- The move from the National Gas Code to the Rules;
- Revisions to Pipeline Services;
- The adoption of terms and conditions that are more in line with recent gas transportation agreements;
- Updating key provisions such as extensions and expansions requirements to reflect recent regulatory practice;
- Adding a capital redundancy mechanism; and
- Removing references to pre-existing contracts as these provisions are not relevant to the revised access arrangement.

These changes are discussed in the following sections.

### 2.2.1 Transfer to National Gas Rules

NT Gas' earlier access arrangement has been revised to be consistent with the National Gas Rules. Revisions 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. Necessary revisions to the earlier access arrangement have been made to:

- Introduction (chapter 1) – substantial rewrite to adopt changes in governing law;
- Reference Tariff Policy (chapter 4) – chapter now called *Determination of total revenue* and describes the building block approach required under the Rules, and refers to revenue and pricing principles set out in the NGL;
- Trading Policy (chapter 6) – chapter now called *Capacity trading requirements* and includes new requirement under the Rules specifying the relationship between the access arrangement and any rules or procedures in a relevant gas market; and
- Glossary – revised definitions of terms in line with the NGL and Rules.

### 2.2.2 Revisions to pipeline services

NT Gas has made some revisions to the description of pipeline services to clarify that the firm and interruptible services are bidirectional. NT Gas has also removed references to the interruptible service being a rebateable service.



### 2.2.3 Revisions to terms and conditions

NT Gas has undertaken a comprehensive revision of the gas transportation terms and conditions in the access arrangement. The terms and conditions in the earlier access arrangement were drafted more than ten years ago and was the first access arrangement drafted by NT Gas.

Since this time, NT Gas' contracting practice, and that of the APA Group to which it belongs, has evolved and the arrangements in the earlier access arrangement no longer correspond with NT Gas' and APA Group's gas transportation arrangements. There are efficiency benefits potentially available to NT Gas, 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. For NT Gas, however, these benefits only arise where there are multiple users of the reference service under the access arrangement, which to date has not occurred.

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.

The following parts of the access arrangement have been substantially revised to adopt consistent arrangements (where possible) with other gas transportation agreements in place for NT Gas and APA Group:

- Pipeline services (chapter 2) – overview of key elements of the firm and interruptible services;
- Reference tariffs and other charges (chapter 5) – details of tariffs and charges applicable to the reference service;
- Capacity Trading requirements (chapter 6) – details on how a user may assign its Contracted Capacity;
- Glossary (schedule 2) – incorporating definitions arising from revised terms and conditions; and
- General terms and conditions (schedule 3) – details of general terms and conditions to apply to all services.

### 2.2.4 Alignment with recent regulatory decisions

NT Gas has revised the extensions and expansions policy included in the earlier access arrangement to bring the policy (now called extension and expansion



requirements) in line with policies in place for other pipelines, and changes in the Rules compared to the National Gas Code.

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.<sup>23</sup>

In line with the earlier access arrangement, NT Gas proposes that NT Gas will elect whether the access arrangement applies to an extension to the pipeline made in the access arrangement period.<sup>24</sup> Further, NT Gas proposes that the access arrangement will apply to expansions to the pipeline, unless NT Gas elects, and the AER agrees, that the access arrangement will not apply to the expansion.<sup>25</sup> These approaches are consistent with approved access arrangements in place for the Goldfields Gas Pipeline<sup>26</sup> and the Roma to Brisbane Gas Pipeline.<sup>27</sup>

Where the access arrangement does apply to an extension or expansion, NT Gas' proposed access arrangement allows NT Gas to elect whether incremental services provided by that extension or expansion are offered as part of the reference service at the reference tariff, or as a negotiated service at a negotiated tariff.<sup>28</sup> This approach allows NT Gas to reach agreement with a user or prospective user over the provision of incremental services by means of an extension or expansion on terms that mean that the costs of the extension or expansion can be recovered from an individual user, or from all users of the reference service, depending on the nature of the extension or expansion, and the services provided. In both cases (whether costs of incremental services are offered as a reference or negotiated service), the extensions and expansions requirements state that the reference tariff will not be affected during the access arrangement period as a result of an extension or expansion.

To ensure that commercial arrangements underpinning an extension or expansion provided as a negotiated service can be maintained for a period that allows the costs of that expenditure to be recovered from the relevant user or users, NT Gas proposes that the election to offer an extension or expansion as a negotiated service be a fixed principle for a period of 15 years, or shorter period as elected by NT Gas.

## 2.2.5 Capital redundancy mechanism

NT Gas 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

---

<sup>23</sup> Rule 104(1)

<sup>24</sup> NT Gas 2010, *Proposed revised access arrangement*, clause 7.1(a)

<sup>25</sup> NT Gas 2010, *Proposed revised access arrangement*, clause 7.2(a)

<sup>26</sup> Economic Regulatory Authority 2010, *Goldfields Gas Pipeline proposed revisions to access arrangement*, 5 August, p 16

<sup>27</sup> APT Petroleum Pipelines Limited 2007, *Access Arrangement for Roma Brisbane Pipeline*, 28 February, p 26

<sup>28</sup> NT Gas 2010, *Proposed revised access arrangement*, clauses 7.1(d) and 7.2(c)



of costs associated with a decline in demand for pipeline services between NT Gas and users, consistent with Rule 85(3).

## 2.2.6 Review of access arrangement

### *Review submission and commencement*

Rule 49 requires that a full access arrangement include a revisions commencement date and a revisions submission date. NT Gas proposes the following revisions commencement and submission dates:

- Revisions commencement date: 1 July 2016
- Revisions submissions date: 1 January 2016

The proposed revisions commencement date is five years after the last revision commencement date (1 July 2011) and is therefore consistent with the 'general rule' under Rule 50.

The proposed revisions submission date aligns with the revisions submission date and time period for regulatory consideration included in the earlier access arrangement. NT Gas considers that this date is consistent with the National Gas Objective as it provides sufficient time for the AER to approve the revised access arrangement within the mandatory timelines set out in Division 8 of Part 8 of the Rules.

## 2.2.7 Other changes to the earlier access arrangement

NT Gas has also made minor revisions to the access arrangement including:

- Moving tariffs out of the body of the access arrangement and into a separate attachment;
- Moving details of terms and conditions for the firm and interruptible service (formerly chapter 3) to either chapter 2 (high level provisions) or schedule 3 (detailed terms and conditions);
- Capitalisation of defined terms; and
- Changes to the order of provisions.







## 3 Regulatory obligations

Compliance with 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 concepts of expenditure incurred by a prudent service provider and accepted good industry practice, which are requirements for both capital and operating expenditure under the Rules.<sup>29</sup> This chapter provides an overview of relevant regulatory obligations applying to NT Gas in its operations in the Northern Territory.

Compliance with regulatory obligations is a key driver of costs for the AGP in operation and maintenance of the pipeline. This section provides an overview of the main regulatory instruments and obligations applying to NT Gas in its operations in NT, and which drive asset management plans and processes for the AGP. The details of regulatory requirements listed here are therefore referenced throughout this submission and in the supporting information provided to the AER in the access arrangement revision proposal. This chapter does not consider regulatory obligations arising from generic legislation such as the Corporations Act that applies to a wide spectrum of businesses across Australia.

### 3.1 National Regulatory Obligations

#### 3.1.1 National Gas Law and National Gas Rules

In July 2008 the new 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 NT Gas 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; and
- Establishment of new arrangements for greenfield developments and scope for light regulation of covered pipelines and networks.

---

<sup>29</sup> NGR 79(1)(a) and 91(1)



NT Gas 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.

NT Gas has also included costs for preparing revisions to the access arrangement in 2015/16 in its forecast operating expenditure proposal.

### 3.1.2 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 CO<sub>2</sub> equivalent, total amount of energy produced and total amount of energy consumed.

NT Gas 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.

## 3.2 Northern Territory Regulatory Obligations

### 3.2.1 Energy Pipelines Act

The key instrument that gives NT Gas authority to operate the AGP is the *Energy Pipelines Act* (NT).

The *Energy Pipelines Act* requires any person who constructs, alters or reconstructs a pipeline (or intends to), as well as any person who operates a pipeline, to hold a licence issued by the responsible minister under the Act.<sup>30</sup> A licence can impose conditions on the licence holder, including that the licence holder comply with specific standards set out in the licence.<sup>31</sup> The Act itself also requires that the licence holder comply with certain prescribed standards.<sup>32</sup>

The Act also includes obligations on the licence holder to restore agricultural land after construction of a pipeline, and establishes a series of environmental offences for land contamination brought about by an act or omission by a licence holder during the conduct of an operation authorised under the Act.<sup>33</sup>

The Minister may give directions to a licence holder on any matter in respect of which regulations may be made under the Energy Pipelines Act.

---

<sup>30</sup> Energy Pipelines Act, s. 12

<sup>31</sup> Energy Pipelines Act, s. 17

<sup>32</sup> Energy Pipelines Act, s. 34

<sup>33</sup> Energy Pipelines Act, Part VA



### 3.2.2 Energy Pipelines Regulations

The Energy Pipeline Regulations set out certain additional obligations on licence holders, as well as specify penalties and the form of applications.

A key obligation under the Regulations is that a licence holder develops a Pipeline Management Plan (PMP) for the construction and operation of a pipeline (as relevant). The PMP must be developed in accordance with the regulations, including requirements that the PMP include:

- A statement of the pipeline licence holder's strategic health and safety objectives for the design, construction, operation, modification and decommissioning of the pipeline<sup>34</sup>;
- A comprehensive description of the pipeline including a description of:
  - the design for the pipeline, the route corridor in which the pipeline is to be constructed and the way in which the pipeline is to be constructed;
  - the compositions of energy-producing hydro-carbons that are to be conveyed through the pipeline when it is operating; and
  - the safe operating limits for conveying those mixtures through the pipeline<sup>35</sup>;
- A comprehensive description of the pipeline management system including a description of:
  - the risk of significant pipeline accident events and other risks to the integrity of the pipeline associated with the design, construction, modification and decommissioning of the pipeline;
  - measures that have been, or will be, implemented to reduce the risks to levels that are as low as reasonably practicable;
  - the systems used to identify, evaluate and manage the risks and measures; and
  - the arrangements for monitoring, auditing and reviewing those systems<sup>36</sup>;
- A description of the Australian Standards and international standards applied, or that will be applied, for the design, construction, operation, modification and decommissioning of the pipeline<sup>37</sup>;
- Arrangements for record management and document availability<sup>38</sup>; and

---

<sup>34</sup> Energy Pipelines Regulations, cl. 27

<sup>35</sup> Energy Pipelines Regulations, cl. 28

<sup>36</sup> Energy Pipelines Regulations, cl. 29

<sup>37</sup> Energy Pipelines Regulations, cl. 30



- Arrangements for reporting to the Minister about the design, construction, operation, modification and decommissioning of the pipeline, at intervals agreed with the Minister, but at least once each year<sup>39</sup>.

The PMP must be submitted to the NT Director of Energy for approval if significant changes to the PMP are made, as well as at least every five years. The Minister may also require a revision to the PMP.<sup>40</sup> Under certain conditions set out in the Regulations, the Minister can refuse to approve a PMP, or withdraw consent to a PMP, which has the effect of withdrawing a licence to construct or operate a pipeline (as relevant).

### 3.2.3 AGP Pipeline licence

NT Gas holds a licence in respect of the covered AGP, spurlines and laterals, as set out in Table 3.1.<sup>41</sup>

**Table 3.1 – NT Gas Pipeline licence relevant to covered pipeline**

| Pipeline name  | Pipeline Licence | Expiry |
|--|------------------|--------|
| Amadeus Basin to Darwin Gas Pipeline<br>Mereenie Field to Tylers Pass Spurline<br>Laterals: <ul style="list-style-type: none"><li>• Tennant Creek</li><li>• Katherine</li><li>• Pine Creek</li><li>• Channel Island</li><li>• Palm Valley Interconnect</li></ul> | 04               | 2011   |

The original licence to construct and operate the pipeline (Licence No 4) was issued for the period 13 December 1985 to 12 December 2006. The licence was then extended in June 1995 for a further five years, and is now due to expire on 12 December 2011.<sup>42</sup>

The AGP licence includes several obligations on NT Gas in addition to those under the Energy Pipelines Act. These include obligations:

- To comply with directions given to the licence holder by the responsible Minister;
- To comply with the Technical specification, Environmental specification and the Operating and Maintenance Manuals; and

<sup>38</sup> Energy Pipelines Regulations, cl. 31

<sup>39</sup> Energy Pipelines Regulations, cl. 32

<sup>40</sup> Energy Pipelines Regulations, cls. 34 and 35

<sup>41</sup> Pipeline Licence No.4 – Amadeus Basin to Darwin Gas Pipeline

<sup>42</sup> Pipeline Licence No.4 – Amadeus Basin to Darwin Gas Pipeline - Renewal



- To carry out operations in relation to the pipeline in accordance with good pipeline practice, including using the most appropriate available technology and producing the minimum environmental degradation that can reasonably be achieved; and
- To ensure that gas transported through the pipeline complies with the specification set out in the licence by testing gas by methods and in frequencies approved by the Director of Energy.

The Licence also requires that NT Gas ensure that the Operating and Maintenance Manuals remain at all times consistent with current good industry practice, and NT Gas must accordingly submit changes to the manuals to the Director of Energy for approval as necessary.

### **3.3 Australian Standards and Codes**

The following Australian Standards and Codes are referred to in relevant legislative instruments as mandatory or preferred standards and are therefore considered to be the primary codes of practice applicable to NT Gas' activities:

- AS2885.1:2007 – Pipelines – Gas and Liquid Petroleum – Part 1 – Design and construction
- AS2885.2:2007 – Pipelines – Gas and Liquid Petroleum – Part 2 – Welding
- AS2885.3:2001 – Pipelines – Gas and Liquid Petroleum – Part 3 – Operations
- AS/NZS2832.1: 1998 – Cathodic Protection of Metals– Part 1 – Pipes and Cables
- API Specification 5L – American Petroleum Institute – Steel Pipe
- API Standard 6D – Specification for Pipeline Valves, Gate, Plug, Ball and Check Valves (14th Edition) March 1971
- APIA – Code of Environmental Practice
- AS4041:2006 – Pressure Piping
- MSS-SP44 – Specification for Flanges
- ASME B31.3 – Chemical Plant and Refinery Piping
- AS 3000:2000 – Electrical Installations (Wiring Rules)
- AS/NZS 3000:2007 – Standard for Wiring Rules
- AS 1210:1997 – Pressure Vessels (Including amendments 1 to 3)
- AS4801 – Occupational Health and Safety



- AS2381 – Electrical Equipment for Explosive Gas Atmospheres - selection, installation and maintenance.
- ISO14000 – Environment
- ISO 31000 – Risk Management
- AS/NZS ISO 9001 – quality accreditation
- AS 3806 – compliance management
- AS 4296 – complaint handling
- AS 4390 – records management; and
- AS 8000 – corporate governance.

Of these listed standards, AS2885.3 is the most important for the day-to-day operation of the pipeline, and its various parts are under rolling review. The AS2885 suite of Standards establishes requirements for the safe design, construction, inspection, testing, operation and maintenance of a land or submarine pipeline constructed from steel pipe, and designed to transport gas or liquid petroleum.

AS2885.3 relates in particular to pipeline operations and integrity, and sets the base standards for integrity of the pipeline, including allowable limits for pipeline rupture risk management.

AS2885.1 was reviewed in 2007 and two new process requirements were added to the standard:

- A requirement to undertake safety management studies; and
- A requirement for facility integrity reviews.

These changes to the standard have not materially changed NT Gas' compliance costs as it previously had a requirement to undertake integrity reviews and safety management. The requirement to undertake safety management studies, however, has had some incremental impact on how NT Gas undertakes its works leading to marginal increases in costs not readily isolatable from underlying operating expenditure.

In general, AS2885 does not require that physical plant already in place be altered to comply with changes in the standard (and the standards it references), except where changes relate to areas of public safety in high consequence areas.

Existing plant is instead grandfathered unless there is an upgrade to an existing facility, in which case the upgrade would trigger a requirement to comply with the relevant revised standard as part of the project. This requirement is driving some expenditure in this access arrangement revision proposal in relation to the Katherine Meter Station upgrade – see project Box 6.1.



### 3.4 Regulatory reporting

NT Gas has a number of regulatory reporting obligations to both the AER and the Northern Territory Government Director of Energy in relation to the AGP.

In November 2008, the AER issued a General Information Order under section 48 of the NGL applying to all service providers of covered pipeline services provided by a transmission pipeline. The Order requires NT Gas, as the service provider of the covered AGP, to submit to the AER an annual compliance report responding to matters set out in the Order. This obligation first applied to AGP in relation to the 2008/09 compliance year.

NT Gas' pipeline licence contains a number of reporting requirements to the Director of Energy. NT Gas must lodge in March and September of each year a status report on the activities undertaken to the AGP over the relevant period including:

- Incidents involving the Pipelines and potential safety problems;
- Environmental management activities undertaken or planned;
- Routine and non-routine maintenance activities undertaken or planned;
- Any inspection or other reports not previously submitted including results of coating surveys, cathodic protection system surveys, and integrity surveys; and
- Details of any measure taken or proposed as a consequence of such inspection or surveys.

NT Gas must also advise the Director Energy as soon as practicable, and if serious within 24 hours, any particulars of:

- Uncontrolled escape or ignition of gas;
- Serious injury or death arising in connection with the operation, modification and decommissioning of the pipeline;
- Any incident involving the pipeline causing loss, destruction or damage to the asset; and
- Any incident involving a threat to the pipeline or a contravention of section 66 of the Act.

NT Gas must also provide the Director of Energy a report on any of these incidents with 28 days of occurrence.

In addition NT Gas, in compliance with the PMP and AS 2885.3, performs inspections and prepares reports to confirm and ensure pipeline integrity and confirm the validity of the threat assessments. These inspections or assessments include but are not limited to:



- Technical risk assessment reviews;
- Location class reviews;
- MAOP review;
- Cathodic Protection system surveys;
- In-line inspection tools inspections;
- Coating surveys;
- Right of Way (ROW) inspections;
- Pressure reduction and over-pressure protection reviews;
- Emergency Management Manual reviews; and
- Operations and Maintenance plan reviews.

The Director of Energy is advised of the results of such inspections, reviews and technical assessments within 28 days of finalisation.





## **4 Pipeline planning and asset management**

This chapter provides an overview of NT Gas' long-term pipeline strategy and direction, planning and governance processes and key documents.

### **4.1 Overarching objectives**

The AGP is operated and maintained in accordance with relevant regulatory obligations. Within this framework, asset maintenance and replacement is conducted on a risk basis, taking account of the full life cycle costs of asset maintenance and replacement, and the consequences of asset failure.

Supply performance is based upon the following key pipeline operating criteria:

- Delivery at appropriate pressure and quality; and
- Operating below MAOP at all times.

Engineering assessments are conducted regularly to review and revise asset functionality and performance requirements in light of changing operational requirements.

### **4.2 Planning components**

There are several key components to NT Gas' planning and asset management strategy, including risk management, operations and maintenance measures, and modification (change management). These strategies are described below.

#### **4.2.1 Risk management**

NT Gas operates in a potentially hazardous industry and recognises that this requires a rigorous and systematic approach to manage risk exposure. NT Gas is committed to ensuring that an integrated risk management system is applied throughout the organisation, one that will specifically address the risks of the industry.

NT Gas recognises that managing risk (especially safety), is best performed when embedded into the organisation's culture. Managing risk then becomes everybody's responsibility. All staff and contractors, as part of their induction, have reinforced an awareness of NT Gas risk management policies. Collective and individual performance is then measured against compliance to these policies and the promotion of continuous improvement.

NT Gas's risk management processes are developed in accordance with ISO 31000 – Risk Management standard and align with the requirements of the pipeline integrity management as defined in AS 2885.3. They comprise the following components:

- Technical risk assessment per AS 2885.1



- Facilities Hazard and Operability (“HAZOP”) and audits (internal and external)
- HSE risk management; and
- Environmental Management Plan as per APIA Code of Environmental Practice.

#### 4.2.2 Operations and maintenance measures

Operation of the pipeline is designed to maintain the pipeline fit for purpose by operating within the structural integrity parameters. In summary, the operational objectives are to:

- Ensure the integrity of the pipeline is maintained;
- Ensure that during normal operation, the operating pressure at any point on the pipeline does not exceed the MAOP, and that transient pressure does not exceed 110 per cent of MAOP;
- Minimise pressure cycling on the pipeline by maintenance of a steady inlet pressure and appropriate use of compression; and
- Ensure the operating temperature of the gas does not deviate from the design limits of the pipeline.

Gas quality on the AGP is monitored by SCADA (Supervisory Control and Data Acquisition) at Palm Valley, Mereenie, Darwin City Gate and Ban Ban Springs. It is essential that gas quality be monitored for energy metering, end users’ equipment integrity, and for the integrity of the pipeline and major installed equipment such as valves, compressors and meter stations.

Maintenance of the pipeline is designed to ensure its long term integrity, functionality and operating capability.

The maintenance and scopes defined in the PMP are determined by risk assessment, HAZOP, manufacturers’ and vendors’ information, historical information and prudent industry practices. NT Gas uses a preventative maintenance, planning and scheduling programs to identify and record scheduled or unscheduled maintenance.

#### 4.2.3 Modification (Change management)

NT Gas has a high level change management policy set out in the PMP that handles modifications to existing pipeline systems by the application of suitable risk management techniques. NT Gas also has in place a technical change management procedure<sup>43</sup> setting out the specific steps for managing changes and modifications to plant, processes and documentation to ensure compliance with AS2885.3.

---

<sup>43</sup> Called the Change Assessment Procedure



The procedures allow for many triggers, either internal or external to NT Gas, to initiate a change assessment and to ensure the relevant representative from NT Gas approves each aspect of the change in line with the AS2885 approvals matrix.

The change management process ensures that:

- Proposed changes have a sound technical and commercial justification and meet relevant codes, standards, statutory and contractual requirements;
- Hazards are identified and managed and changes do not compromise the health, safety and the environmental standards;
- Documents such as drawings, manuals and procedures are updated to reflect any changes made;
- Changes are reviewed and approved by people with the relevant competencies and all relevant stakeholders are included in the assessment where appropriate;
- The risk register and the pipeline risk assessment manual are continuously updated; and
- A documented and auditable process is followed.

The techniques and methodologies used in this process are derived from the relevant technical and risk assessment processes available. These processes include, but are not limited to:

- AS 2885.1 qualitative risk assessment that is based on ISO 31000 (Risk Management);
- Job hazard analysis;
- HAZOP;
- Integrity assessments; and
- Cost analysis.

#### 4.2.4 Emergency response

As the operating authority of the AGP, NT Gas recognises the need to plan for incidents that may occur and to periodically test these plans to assess and improve responses in the event of an actual emergency. NT Gas has developed an Emergency Response Manual in accordance with AS 2885.3.

The Emergency Response Manual defines policies, practices and procedures in case of an emergency and is intended to:

- Provide all personnel with a safe, efficient, effective and coordinated response plan to any emergency;



- Define the roles, responsibilities and required actions of personnel in the event of an emergency;
- Control or limit any effect that an emergency may have on the safety of personnel, the public, the environment and the integrity of supply;
- Facilitate resumption of normal operations as soon as possible;
- Provide a basis for training personnel in emergency situations and maintain the required competencies;
- Ensure adequate personnel and equipment to carry out the Emergency Response Manual;
- Detail the interaction and coordination with other emergency service groups and third parties;
- Provide a basis for continuous improvement through review following an emergency, emergency exercise or document review; and
- Meet the requirements of the regulatory bodies, pipeline licences conditions and the appropriate Australian Standards.

NT Gas also has in place a Natural Gas handbook that is a public document that, amongst other things, sets out emergency response procedures for the general public in the event of an emergency. The handbook also includes information about safe working around gas infrastructure and easements, and how to protect gas pipelines from rupture (such as dial before you dig services) and is part of NT Gas' risk management approach to ensure the ongoing integrity of the pipeline and safety of the public.

#### 4.2.5 Records management

NT Gas has a Records Management Plan in place describing the methods used to properly identify, control, and store records that are necessary to safely operate and maintain the pipeline. These records may assist in determining the fitness of the pipeline at any stage of the pipeline operating life.

The Records Management Plan includes:

- Identification of records to be maintained in accordance with legislative, statutory and contractual requirements;
- Retention requirements for those records;
- An outline of the appropriate storage methods to preserve required records; and
- Record maintenance policies so that obsolete records and procedures are removed from circulation.



The Records Management Plan has also been prepared to satisfy requirements under AS2885.3 for:

- Design, construction and commissioning records;
- Operation and maintenance records; and
- Decommissioning records if facilities are decommissioned.

## **4.3 Key planning and asset management documents**

NT Gas has developed a number of planning documents to assist in the development and management of the pipeline, and to comply with relevant regulatory obligations. Key documents are:

- Asset Management Plan, including:
  - Lifecycle plan
- Pipeline Management Plan, including:
  - Safety and Operating Plan;
  - Environmental Management Plan; and
  - Records Management Plan.

These are described in more detail below.

### **4.3.1 Asset Management Plan**

The AGP Asset Management Plan (AMP) contains the rolling five year plan for non-routine capital and operating expenditure for the pipeline, with some longer term projects such as intelligent pigging programs included. The AMP is limited to pipeline facilities and does not cover other facilities such as buildings, computers, desks, vehicles, small plant and equipment. The AMP is reviewed and revised on an annual basis.

The Pipeline Licence, AS2885 and other mandatory or statutory Standards and Regulations form the basis of compliance requirements addressed in the AMP. Other capital and operating works are determined by operator experience, integrity considerations and risk assessment.

A key component of the AMP is the Lifecycle Plan, which addresses pipeline, station, rotating equipment, plant and easement condition, and associated expenditure requirements.

The AMP also includes detailed project descriptions and costings.



#### 4.3.2 Pipeline Management Plan

The Energy Pipelines Regulations requires each licence holder to develop a Pipeline Management Plan (PMP) in accordance with the Regulations, the pipeline licence, and relevant ministerial directions. As NT Gas holds several pipeline licences across the Northern Territory, and operates a number of pipelines for other licence holders, it has prepared a combined PMP in compliance with its obligations across a number of pipelines. The PMP therefore applies more broadly than the covered AGP, and also satisfies requirements for uncovered pipelines such as the Weddell and Wickham Point lateral pipelines.

##### *Policy Statement*

The policy statement for the PMP is:

NT Gas Pty Limited, as operating authority (as defined in AS 2885.3) and/or pipeline licensee is committed to achieving full compliance with the Energy Pipelines Act and Regulations in order to achieve the safe management of these pipelines.

To achieve this objective, NT Gas has prepared the PMP for the operation, modification and decommissioning stages of each pipeline. The PMP documents measures to ensure the:

- Protection of the relevant pipelines and associated facilities;
- Safety of the public;
- Safety of personnel working on the relevant pipelines;
- Safety of contractors;
- Minimisation of environmental impacts; and
- Effective incident management.

NT Gas maintains quality accreditation to AS/NZS ISO 9001 to achieve these objectives.

##### *Scope*

The PMP has been prepared in accordance with the requirements of the Energy Pipelines Regulations and the guidelines set by Australian Standard AS 2885.3 Pipelines – Gas and Liquid Petroleum Part 3: Operation and Maintenance.

Accordingly, as required in Division 2 Part 4 of the Regulations, the PMP includes the following matters:

- Description of safety policy;
- Description of the pipelines;



- Description of the management system;
- Description of standards; and
- Arrangements for reporting and document accessibility.

In addition, the PMP also caters for the requirements of AS 2885.3 clause 4.2, which includes the following matters:

- Description of organisation structure and responsibilities of key positions;
- Description of the pipeline system operation;
- Risk assessment in accordance with AS 2885.1 Pipelines – Gas and Liquid Petroleum Part 1: Design and Construction;
- Summary of operational and maintenance processes and procedures;
- Summary of the content of the emergency response plan;
- Summary of the records management plan; and
- Details of the audit schedule.

The overall structure of the PMP follows the outline of AS 2885.3 requirements.

## **4.4 Expenditure governance**

NT Gas has in place a detailed budget development and expenditure governance process to ensure that all expenditure is prudent and efficient.

As part of the contractual arrangement with PWC in place throughout the earlier access arrangement period, NT Gas developed detailed budgets for expenditure for the following financial year that were approved by PWC. These budgets include explanations for all variations from the previous budget that were greater than 5 per cent and \$5,000.

In addition to budget approval, all expenditure on capital assets greater than \$1000 (regardless of whether they are in an approved budget) require completion of an operating capital request form or more detailed project analysis which includes details of the proposed asset acquisition, need for the asset, consideration of options and budget. NT Gas also obtains three quotes (where possible) for all capital purchase above \$1,000.

The completed OCR form must be approved by a manager with the appropriate delegation for the expenditure level, and then the actual expenditure must be reconciled against the approved expenditure and any variance explained.



#### 4.4.1 Allocation between regulated and non-regulated works

NT Gas has a robust process in place for allocating its costs and revenue between regulated and non-regulated activities to ensure that there is no cross subsidisation between regulated and non-regulated activities.

All expenditures are directly coded to job numbers created for non-regulated activities. These expenditures are directly allocated to those non-regulated activities and are not included in the capital and operating expenditure discussed in the following sections. Every NT Gas employee also completes a timesheet which must be submitted to their leader for approval on a weekly basis. These timesheets accurately record time spent on non-regulated activities and all such time is not included in recorded expenditure on regulated assets.

All capital expenditure is also directly allocated to the asset to which it relates based on actual capital spent.





## 5 Pipeline demand and utilisation

This chapter of the submission discusses pipeline demand and utilisation over the earlier access arrangement period, and provides a forecast of pipeline demand and utilisation over the access arrangement period.

### 5.1 Demand and utilisation during earlier access arrangement period

This section sets out usage of the pipeline over the earlier access arrangement period and discusses key drivers and trends for that usage.

#### 5.1.1 Gas demand and volumes over the earlier access arrangement period

##### *Total gas demand*

Total gas demand on the AGP by delivery point over the earlier access arrangement period is shown in Figure 5.1 over the page.

As can be seen from the graph, gas demand dipped significantly between 2006/07 and 2009/10, before returning to trend in 2010/11. The reason for the drop in observed demand was a significant shortfall in the availability of gas reserves from the Amadeus Basin from September 2007 to August 2009. Gas used in electricity generation for the Darwin and Katherine loads was supplemented by diesel generation over this period. In addition, load at Weddell was supplied from the Wickham Point Pipeline (from the Conoco Phillips LNG facility).

Figure 5.2 shows total implied demand for the pipeline over the earlier access arrangement period, with the addition of an estimate of gas demand met through diesel substitution at Channel Island<sup>44</sup>. After 'correction' for the period of fuel substitution, the underlying gas demand trend over the earlier access arrangement period shows a relatively steady increase of 3.2 per cent per annum.

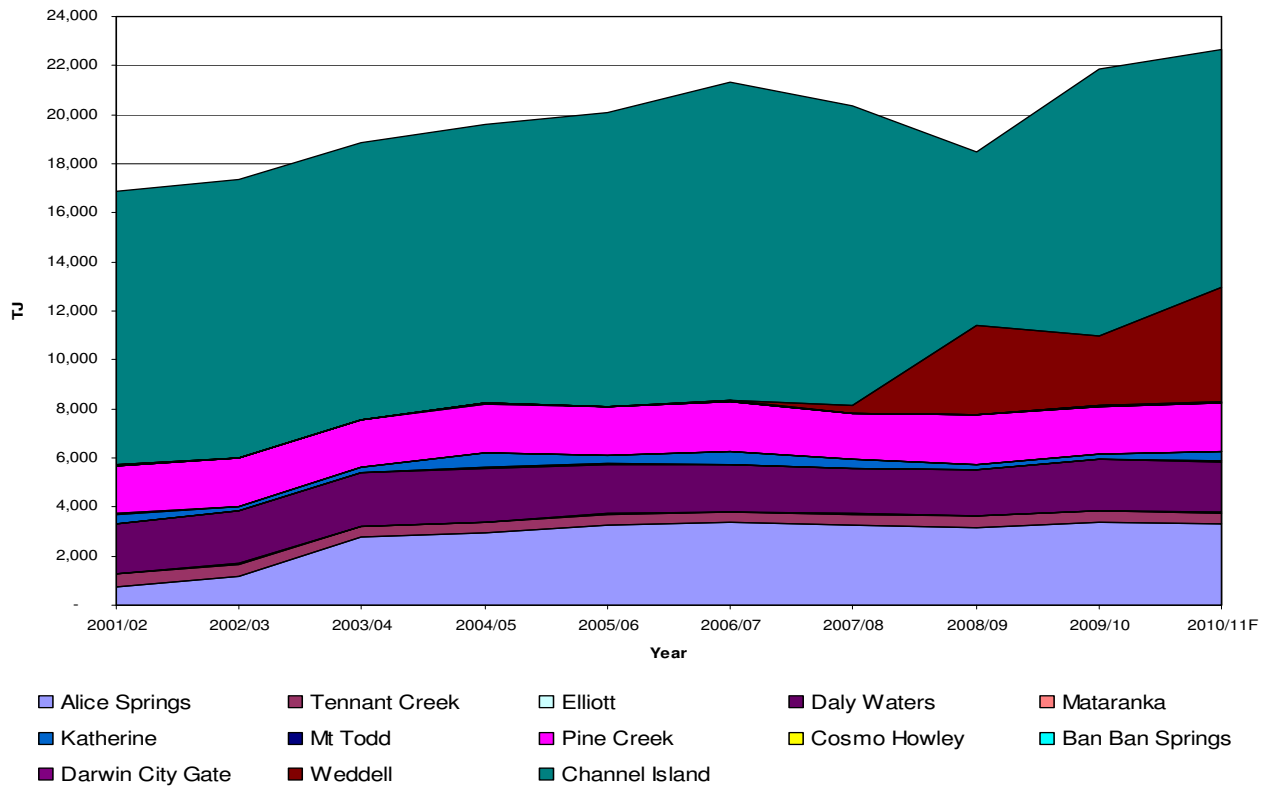
The return to trend in total gas demand in 2009/10 (Figure 5.1) corresponds with the new availability of gas from the Blacktip gas field delivered into the AGP at Ban Ban Springs, reinstating gas as the sole fuel for electricity generation at Channel Island, supplying Darwin.<sup>45</sup>

---

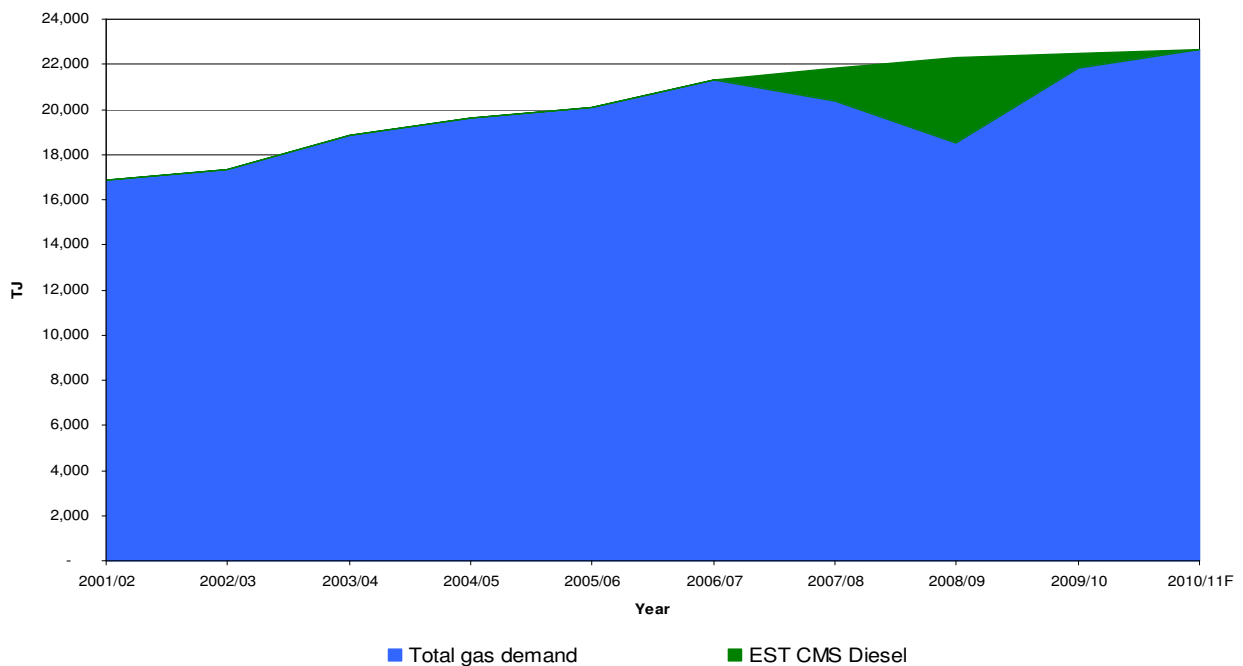
<sup>44</sup> The diesel substitution value has been derived by extrapolating the seasonal usage trends and profile for Channel Island in the years preceding the supply shortfall, as well as actual figures available for 2009/10, to give an estimate of foregone gas demand during the shortfall period at this delivery point. There was also some minor diesel fuel substitution at Alice Springs during the gas shortfall period.

<sup>45</sup> Diesel may be used in an emergency situation.

**Figure 5.1 – Total gas demand over the earlier access arrangement period by delivery point**



**Figure 5.2 – Total gas and substitute demand over the earlier access arrangement period**





As a consequence, Blacktip field gas has replaced Amadeus Basin gas as the primary gas transported along the pipeline, and has consequently reversed the predominant direction of gas flow on the AGP south of Ban Ban Springs to a net southerly flow.

### *Demand by delivery point*

Table 5.2 at the end of this section shows actual and estimated minimum, maximum and average demand and volumes by delivery point over the earlier access arrangement period.

As can be seen from the table, delivery points along the pipeline show different trends in demand and volumes. These trends largely relate to the principal end-use or purpose for gas delivered at that delivery point. For example, if gas delivered to a delivery point is used by a single or a small number of mines for electricity generation, then demand will reflect the success or otherwise of that mine over the period. In contrast, if gas supplied is primarily used for electricity generation for domestic, commercial and small industrial consumption, then usage of gas is likely to follow trends similar to that found in electricity network demand forecasts with demand drivers such as appliance use and efficiency, population growth and demographics, and weather being important. For these markets, an additional layer driving demand may also be positive or negative step changes in electricity generation where older generating units are replaced by more efficient units, or additional generating units are added. Overlaid on these trends is the effect of the shortfall of gas described above which impacts demand at some delivery points.

Table 5.1 below describes each delivery point on the AGP by their primary gas usage characteristics, and provides a high level explanation for any specific trends in demand and volumes observed for those delivery points. Further details of drivers of demand are discussed in relation to demand forecasts, and are relevant to both the earlier access arrangement period and the access arrangement period.



**Table 5.1 – Gas usage characteristics and drivers of demand and volumes at each delivery point**

| Delivery Point   | Usage characteristics   |
|------------------|---|
| Alice Springs    | Off take point to the Alice Springs pipeline that supplies gas for local electricity generation for domestic commercial and light industrial end uses. The demand profile for this delivery point changed in 2003/04 with the full utilisation of the Palm Valley interconnect. From this time gas deliveries (demand and volumes) showed a steady increase reflecting increased electricity generation demand. |
| Tennant Creek    | Supplies gas for local electricity generation for domestic commercial and light industrial end uses, in addition to supplying some mining operations. Gas deliveries show a steady increase with demand and volumes varying due to factors such as weather.   |
| Elliott          | Supplies gas for local electricity generation for the local township, with some shifting in primary fuel used for generation over the period affecting demand and volumes.  |
| Daly Waters      | Off take point for the pipeline to the Macarthur River Mine, which mines lead, silver and zinc. Operation of this mine was impacted by a downturn in the commodities market in 2005/06 and 2006/07, followed by lower consumption as a result of a delay in the mine getting environmental approval for open cut operations in 2007/08. Demand and volumes have increased from 2008/09.                         |
| Mataranka        | Supplies a local lime plant to fuel a kiln. The kiln is dual fuel and subject to variable energy mix based on market price for waste oil, which is reflected in actual gas demand and volumes. In August 2009, the operation's interruptible gas supply ceased as gas was not available for purchase.   |
| Katherine        | Supplies gas for local electricity generation for domestic commercial and light industrial end uses. Generation units used as peaking supply for the Darwin/Katherine grid, leading to some fluctuation in usage over the period.   |
| Mt Todd          | Supplied gas to single mine operation. Mine ceased operation prior to start of the earlier access arrangement period and went into care and maintenance mode.   |
| Pine Creek       | Supplies gas to independent power plant to supply electricity to the local township and base load for the electricity transmission network. Demand and volumes show annual variability largely attributable to weather variations driving electricity demand.   |
| Cosmo Howley     | Supplied gas to single mine operation. Mine ceased operation prior to start of the earlier access arrangement period and went into care and maintenance mode. Cosmo lateral decommissioned in 2008.   |
| Ban Ban Springs  | New supply of gas in 2009. Gas delivered to this point was used to commission the Bonaparte Gas Pipeline in 2008 and 2009.  |
| Darwin City Gate | Supplies gas to the Darwin distribution system for commercial and light industrial uses.  |
| Weddell          | Supplies gas for local electricity generation for domestic commercial and light industrial end uses. Gas deliveries started in 2008.  |
| Channel Island   | Supplies gas for local electricity generation for domestic commercial and light industrial end uses. Demand and volumes show a steady increase reflecting increased electricity generation demand, with the exception of the period from September 2007 to August 2009 when there was a gas supply shortfall and generation was supplemented by significant amounts of diesel.                                  |



### 5.1.2 User numbers over the earlier access arrangement period

Table 5.3 at the end of this section shows user numbers by delivery point over the earlier access arrangement period. As discussed above, use of the pipeline is dominated by a single user, PWC, which is the only user providing gas to end users at a number of delivery points.

Users other than PWC are identifiable in the table where the number of users at the delivery point is greater than one. The duration of these user contracts is generally short (1-3 years). This is the result of:

- the lack of available gas and/or capacity over a long contracting period;
- the interruptible nature of gas contracts available; and
- the nature of the contracting parties, which were generally relatively itinerant, such as mining ventures.

These drivers largely remain in place over the access arrangement period, with the exception of gas availability, which was resolved with the connection of the Bonaparte Gas Pipeline, bringing gas from the Blacktip gas field.

### 5.1.3 Pipeline capacity and utilisation over the earlier access arrangement period

#### *Pipeline capacity*

NT Gas calculates the capacity of the pipeline as the amount of gas the AGP can deliver on a daily basis over a two week period while maintaining line pack and delivery point pressures.

Under south to north free flow conditions, the capacity of the pipeline is 44TJ/day, however, with the Warrego compressor, south to north capacity is approximately 54TJ/day. These conditions were in place on the pipeline until 2009/10, when the capacity of the pipeline notionally increased to 104TJ/day with the connection of the Bonaparte Gas Pipeline.<sup>46</sup>

Actual capacity values over the early years of the period were impacted by the mix of gas coming from the Palm Valley and Mereenie gas fields and their relative heating values. As shown in Table 5.4 at the end of the section, capacity of the pipeline increased slightly in 2005/06 when the relative proportion of Palm Valley gas decreased significantly, which increased the capacity of the pipeline as Mereenie gas has a slightly higher heating value compared to Palm Valley gas.

---

<sup>46</sup> The expected capacity is 104TJ/day based on modeling results for delivery of gas from the Bonaparte Gas Pipeline. This value has not been verified through actual conditions and could vary depending on the location of load.



The significant change in capacity of the pipeline resulting from the connection of the Bonaparte Gas Pipeline is a function of both gas pressure and the distance travelled by gas. Gas enters the pipeline at Ban Ban Springs at close to MAOP due to the higher MAOP of the Bonaparte Gas Pipeline, and travels a shorter distance before offtake compared to gas injected from the Amadeus Basin. This has the effect of increasing the capacity of the pipeline.

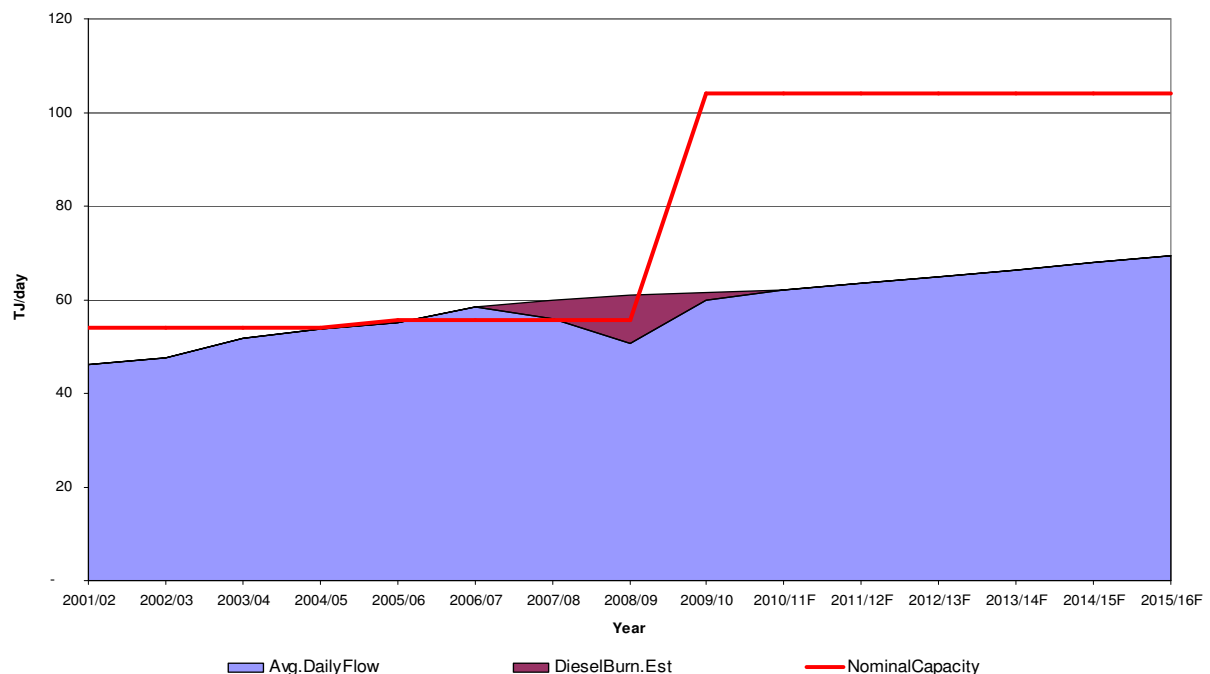
### *Pipeline Utilisation*

Utilisation in the earlier access arrangement period has been calculated using actual maximum demand in each year divided by the capacity of the pipeline.

Utilisation of the pipeline up until 2008/09 matched expectations with utilisation exceeding capacity of the pipeline by a small factor.<sup>47</sup> The reduction in utilisation of the pipeline in 2008/09 corresponds with the shortfall in gas availability where less gas was transported through the pipeline and diesel substituted for gas in electricity generation at Channel Island. Diesel substitution started in September 2007.

The connection of the Bonaparte Gas Pipeline reset capacity, leading to a reduction in percentage utilisation of the pipeline, however daily usage continued to climb in line with the trend over this period as shown Figure 5.3 below.

**Figure 5.3 – Daily volumes over the earlier access arrangement period against pipeline capacity**



<sup>47</sup> Utilisation factors greater than the capacity occur where there have been a number of short term unsustainable overruns in gas usage.



Over the earlier access arrangement period, NT Gas has also experienced an increase in the 'peakiness' of gas demand, related to increased peakiness of electricity generation. This appears related to increased utilisation of domestic reverse cycle air conditioning in the NT.<sup>48</sup> As an example, average daily peak demand was 117 per cent of average demand in 2001/02, but this ratio had risen to 130 per cent in 2010/11.

---

<sup>48</sup> Energy Efficient Strategies 2006, *Status of air-conditioners in Australia: updated with 2005 data: Report for NAEEEEC 2005/09 (updated)*, January, p 51



**Table 5.2 – Minimum, maximum and average demand and total volume by delivery point over the earlier access arrangement period**

|                 |                | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|-----------------|----------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Delivery points | Unit           |         |         |         |         |         |         |         |         |         |          |
| Alice Springs   | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 3.6     | 6.2     | 6.1     | 4.1     | 1.3     | 4.2     | 5.0      |
|                 | Max (TJ/d)     | 7.0     | 12.0    | 31.2    | 12.4    | 12.7    | 13.1    | 13.3    | 13.4    | 14.5    | 15.3     |
|                 | Average (TJ/d) | 2.0     | 3.2     | 7.6     | 8.0     | 8.9     | 9.2     | 9.0     | 8.7     | 9.3     | 9.0      |
|                 | Total (TJ/a)   | 738.2   | 1,162.9 | 2,789.4 | 2,933.4 | 3,247.5 | 3,356.9 | 3,280.2 | 3,186.8 | 3,381.8 | 3,300.0  |
| Tennant Creek   | Min (TJ/d)     | 0.4     | 0.7     | 0.1     | 0.3     | 0.7     | 0.2     | 0.6     | 0.7     | 0.5     | 0.5      |
|                 | Max (TJ/d)     | 2.7     | 2.3     | 1.9     | 1.8     | 2.3     | 1.7     | 1.7     | 1.8     | 1.8     | 1.9      |
|                 | Average (TJ/d) | 1.5     | 1.4     | 1.1     | 1.2     | 1.3     | 1.2     | 1.2     | 1.2     | 1.2     | 1.3      |
|                 | Total (TJ/a)   | 521.9   | 518.6   | 414.0   | 426.4   | 457.2   | 432.2   | 430.0   | 445.4   | 452.1   | 465.0    |
| Elliott         | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|                 | Max (TJ/d)     | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     | 0.2     | 0.2     | 0.2     | 0.2      |
|                 | Average (TJ/d) | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     | 0.0     | 0.1     | 0.1     | 0.1     | 0.1      |
|                 | Total (TJ/a)   | 18.7    | 27.3    | 25.5    | 21.2    | 21.1    | 11.8    | 28.7    | 37.3    | 38.7    | 37.0     |
| Daly Waters     | Min (TJ/d)     | 1.7     | 0.4     | 1.6     | 1.5     | 0.6     | 1.3     | 0.0     | 0.0     | 1.2     | 0.0      |
|                 | Max (TJ/d)     | 7.1     | 9.0     | 7.3     | 7.6     | 6.9     | 6.4     | 7.4     | 10.9    | 7.7     | 8.0      |
|                 | Average (TJ/d) | 5.6     | 5.9     | 5.9     | 6.0     | 5.5     | 5.3     | 5.0     | 5.0     | 5.7     | 5.5      |
|                 | Total (TJ/a)   | 2,038.2 | 2,135.8 | 2,158.7 | 2,194.3 | 2,022.0 | 1,916.5 | 1,823.5 | 1,836.7 | 2,078.5 | 2,025.0  |





|            |                | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|------------|----------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Mataranka  | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Max (TJ/d)     | 0.1     | 0.2     | 0.2     | 0.2     | 0.2     | 0.2     | 0.2     | 0.1     | 0.0     | 0.2      |
|            | Average (TJ/d) | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     | 0.0     | 0.0     | 0.0     | 0.1      |
|            | Total (TJ/a)   | 26.2    | 35.4    | 26.1    | 32.7    | 44.9    | 22.5    | 9.5     | 4.0     | 0.0     | 50.0     |
| Katherine  | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Max (TJ/d)     | 5.0     | 3.6     | 4.3     | 5.9     | 5.5     | 6.2     | 4.5     | 5.4     | 4.2     | 11.8     |
|            | Average (TJ/d) | 0.9     | 0.4     | 0.5     | 1.6     | 0.9     | 1.4     | 1.0     | 0.6     | 0.6     | 1.1      |
|            | Total (TJ/a)   | 331.1   | 149.3   | 189.1   | 592.8   | 314.9   | 518.1   | 365.2   | 226.8   | 223.9   | 405.0    |
| Mt Todd    | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Max (TJ/d)     | 3.3     | 1.6     | 0.0     | 0.0     | 0.7     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Average (TJ/d) | 0.2     | 1.6     | 0.0     | 0.0     | 0.7     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Total (TJ/a)   | 68.8    | 1.6     | 0.0     | 0.0     | 0.7     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
| Pine Creek | Min (TJ/d)     | 2.5     | 1.7     | 0.5     | 2.6     | 1.7     | 3.1     | 2.6     | 2.2     | 0.5     | 0.5      |
|            | Max (TJ/d)     | 6.7     | 6.0     | 5.8     | 7.1     | 6.2     | 6.9     | 5.9     | 7.1     | 6.4     | 7.0      |
|            | Average (TJ/d) | 5.3     | 5.4     | 5.4     | 5.5     | 5.4     | 5.7     | 5.1     | 5.5     | 5.2     | 5.4      |
|            | Total (TJ/a)   | 1,935.1 | 1,966.6 | 1,966.1 | 2,015.4 | 1,974.3 | 2,063.5 | 1,875.0 | 2,010.3 | 1,896.8 | 1,986.0  |
| Cosmo      | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Max (TJ/d)     | 1.3     | 0.4     | 0.0     | 1.3     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Average (TJ/d) | 0.1     | 0.0     | 0.0     | 0.1     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |
|            | Total (TJ/a)   | 23.7    | 1.0     | 0.3     | 27.2    | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0      |



|                     |                     | 2001/02         | 2002/03         | 2003/04         | 2004/05         | 2005/06         | 2006/07         | 2007/08         | 2008/09         | 2009/10         | 2010/11F        |
|---------------------|---------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Ban Ban Springs     | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                     | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 8.5             | 9.0             | 0.0             |
|                     | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.2             | 0.0             |
|                     | Total (TJ/a)        | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 8.5             | 77.7            | 0.0             |
| Darwin City Gate    | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                     | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.1             | 0.5             | 0.3             | 0.0             | 0.0             |
|                     | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                     | Total (TJ/a)        | 8.4             | 8.2             | 9.1             | 9.2             | 8.7             | 9.0             | 14.0            | 12.9            | 9.6             | 10.0            |
| Weddell             | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                     | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 9.3             | 18.5            | 17.5            | 18.0            |
|                     | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.8             | 9.9             | 7.7             | 12.8            |
|                     | Total (TJ/a)        | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             | 303.7           | 3,626.4         | 2,803.9         | 4,670.0         |
| Channel Island      | Min (TJ/d)          | 19.3            | 19.6            | 16.0            | 15.5            | 15.7            | 15.3            | 14.9            | 3.4             | 0.0             | 9.0             |
|                     | Max (TJ/d)          | 50.1            | 45.3            | 43.4            | 51.2            | 51.2            | 56.5            | 51.2            | 37.2            | 44.5            | 52.0            |
|                     | Average (TJ/d)      | 30.6            | 31.1            | 30.9            | 31.2            | 32.9            | 35.6            | 33.5            | 19.4            | 29.9            | 26.6            |
|                     | Total (TJ/a)        | 11,158.7        | 11,353.7        | 11,280.1        | 11,374.4        | 12,024.2        | 13,005.0        | 12,251.0        | 7,097.8         | 10,895.8        | 9,725.0         |
| <b>Total volume</b> | <b>Total (TJ/a)</b> | <b>16,869.0</b> | <b>17,360.4</b> | <b>18,858.3</b> | <b>19,627.1</b> | <b>20,115.4</b> | <b>21,335.6</b> | <b>20,380.9</b> | <b>18,493.0</b> | <b>21,858.7</b> | <b>22,673.0</b> |



**Table 5.3 – User numbers by delivery point over the earlier access arrangement period**

| Delivery Points  | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Alice Springs    | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Tennant Creek    | 2       | 2       | 2       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Elliott          | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Daly Waters      | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Mataranka        | 1       | 1       | 1       | 1       | 1       | 2       | 2       | 1       | 1*      | 1        |
| Katherine        | 2       | 2       | 2       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Mt Todd          | 1       | 1       | 0       | 0       | 1       | 0       | 0       | 0       | 0       | 0        |
| Pine Creek       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |
| Cosmo            | 1       | 1       | 1       | 1       | 0       | 0       | 0       | 0       | 0       | 0        |
| Ban Ban Springs  | 0       | 0       | 0       | 0       | 0       | 0       | 0       | 1       | 1       | 0        |
| Darwin City Gate | 1       | 1       | 1       | 1       | 1       | 2       | 2       | 2       | 1       | 1        |
| Weddell          | 0       | 0       | 0       | 0       | 0       | 0       | 1       | 1       | 1       | 1        |
| Channel Island   | 2       | 2       | 1       | 1       | 1       | 1       | 1       | 1       | 1       | 1        |

\* While there was one contracted user at this delivery point in 2009/10, no gas was delivered to this user as gas was to be supplied under an interruptible contract and no gas was available for delivery.

**Table 5.4 – Pipeline capacity and utilisation over the earlier access arrangement period**

|   | Units  | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|---|--------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| <b>Pipeline capacity</b>                | TJ/day | 54.1    | 54.1    | 54.1    | 54.1    | 55.6    | 55.6    | 55.6    | 55.6    | 104.0   | 104.0    |
| <b>Utilisation of pipeline capacity</b> | %      | 108     | 103     | 102     | 108     | 105     | 110     | 107     | 96      | 75      | 77       |



## 5.2 Demand and utilisation forecasts

NT Gas has prepared a forecast of total gas demand for the AGP over the access arrangement period, as well as forecasts for pipeline capacity and utilisation as required under the Rules.<sup>49</sup>

### 5.2.1 Gas demand forecast methodology

#### *Average demand*

NT Gas has developed its forecast for each delivery point based on an analysis of:

- historic trends in gas volumes and maximum demand for each delivery point, taking account of periods of forced fuel substitution brought about by the shortfall in gas availability; and
- the drivers for gas demand for each delivery point.

These forecasts have then been checked against available PWC forecasts and other information on gas inputs into the pipeline to deliver both a bottom up and top down forecast for each delivery point and for the pipeline as a whole.<sup>50</sup> NT Gas considers that its forecast is arrived at on a reasonable basis, and represents the best forecast or estimate possible in the circumstances.

NT Gas sought information from PWC to assist it in developing its demand forecast, in particular longer term forecasts of gas deliveries into the pipeline at Ban Ban Springs and expected demand for end users at each delivery point. PWC declined to assist NT Gas by providing this information.

In its place, NT Gas has adopted the methodology described above, and used historic demand information for each delivery point, including known load characteristics, to develop a reasonable forecast for each delivery point. This has been assisted in the early part of the forecast period (2010/11) by PWC annual demand forecasts as required under existing contractual arrangements.<sup>51</sup>

#### *Maximum demand*

To forecast maximum demand for each delivery point, NT Gas has adopted a number of approaches depending of the nature of demand at each point.

---

<sup>49</sup> Rule 72(1)(B)(d)

<sup>50</sup> PWC delivery point forecasts for 2010/11 are provided with the supporting documents for this submission.

<sup>51</sup> **Confidential footnote**



For Tennant Creek, Pine Creek and Elliott, NT Gas has forecast maximum daily demand in line with gas requirements to fuel the maximum output of generators installed at these sites. Maximum demand for these sites does not grow over the period, as generation capacity is not expected to be increased at these sites.

For Daly Waters, Mataranka and Darwin City Gate, maximum daily demand is based on historical values without forecast growth, in line with the characteristics of load at those sites.

Maximum demand at the Katherine and Alice Springs has been derived based on maximum daily quantities advised by PWC, growing at the same rate as volumes over the access arrangement period. This is because generating capacity served is either unknown (Alice Springs) or the expected utilisation of the generating capacity does not provide a reasonable basis on which to estimate maximum demand for the access arrangement period.

For Weddell, where there is limited historical information on maximum demand, NT Gas has averaged the last two years of the period (where Weddell was at full generating capacity) and applied this value as a maximum value for 2010/11. Similarly for Channel Island, NT Gas has calculated maximum demand based on the average of the five highest maximum values observed over the earlier period, applied this value as the maximum value in 2010/11. Maximum demand at both delivery points is then forecast to grow at the same rate as volumes for these points over the access arrangement period (3 per cent per annum), however maximum demand at Channel Island is capped at 60TJ/day in 2015/16. The reason for this cap is discussed below.

### 5.2.2 Total gas demand

Total gas demand for the pipeline is forecast to grow at an average of 2.2 per cent per annum over the access arrangement period. This is shown graphically by delivery point in Figure 5.4 below.

As discussed above, this forecast has been derived by developing a bottom up forecast for each delivery point, taking account of the unique characteristics of each delivery point that drive demand. This combined forecast is then checked against available demand information from PWC.

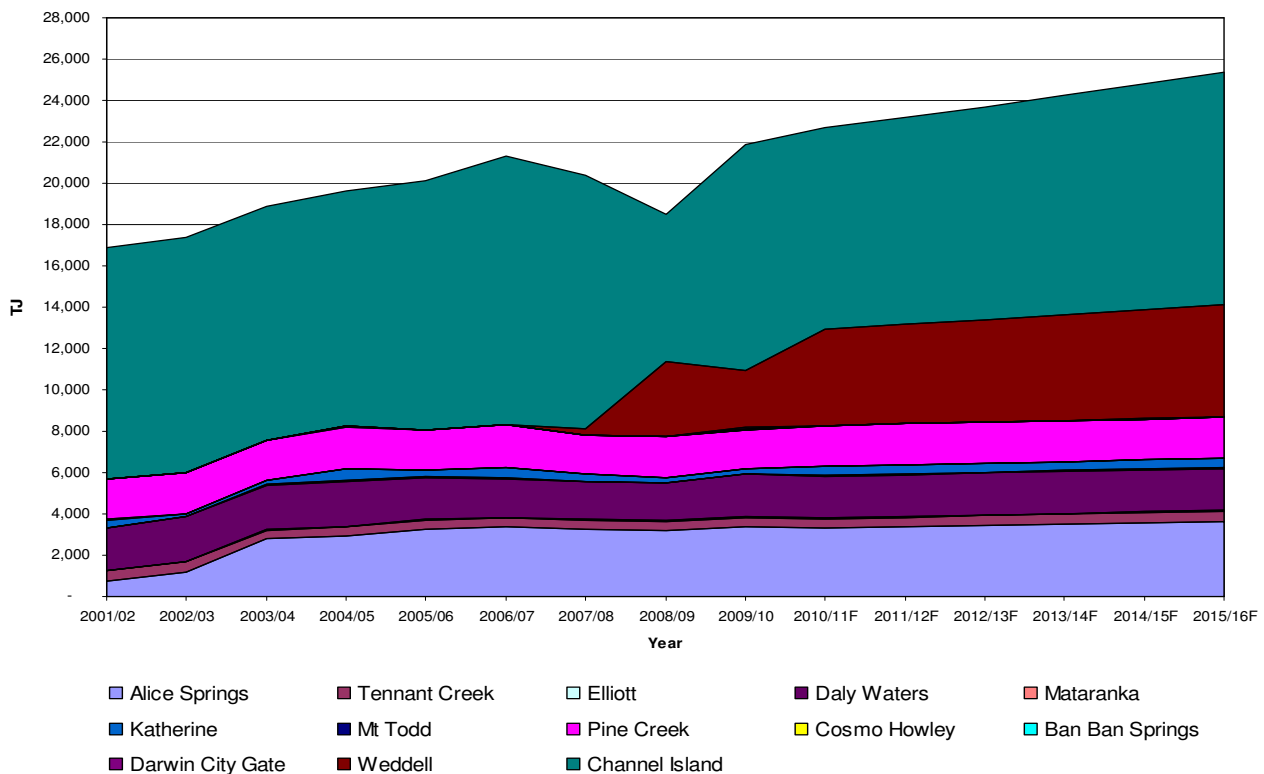
The slightly lower forecast growth rate compared to the earlier access arrangement is largely a result of the factors driving demand at each delivery point, but also reflects some more general drivers that impact gas use in NT, including:

- Improved efficiency of recently installed PWC electricity generating units;
- Drivers for PWC to improve efficiency in the utilisation of its installed generation units, largely by prioritising the use of the most efficient generating units (which can be seen by the move away from Channel Island demand towards Weddell shown below); and

- Slowing population growth throughout NT, as well as an easing in economic growth.<sup>52</sup>

Further detail on drivers of demand for each delivery point is set out in the following section.

**Figure 5.4 – Actual and forecast total gas demand over the access arrangement period**



### 5.2.3 Gas demand delivery point forecasts

Forecast minimum, maximum and average demand, and total volume by delivery point, is shown in Table 5.5 below.

Similar to the discussion of key trends behind actual demand in the earlier access arrangement period (see section 5.1.1), each delivery point exhibits different drivers that lead to different demand forecasts. These are discussed in the following sections.

<sup>52</sup> Northern Territory Government 2009, *Northern Territory Population Projections*, July; Access Economics 2010, *Economic brief*, September quarter 2010



**Table 5.5 – Forecast minimum, maximum and average demand and total volume by delivery point over the access arrangement period**

|                 |                | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|-----------------|----------------|---------|---------|---------|---------|---------|
| Delivery points |                |         |         |         |         |         |
| Alice Springs   | Min (TJ/d)     | 5.0     | 5.0     | 5.0     | 5.0     | 5.0     |
|                 | Max (TJ/d)     | 15.6    | 15.9    | 16.2    | 16.5    | 16.8    |
|                 | Average (TJ/d) | 9.2     | 9.4     | 9.6     | 9.8     | 10.0    |
|                 | Total (TJ/a)   | 3,366.0 | 3,433.3 | 3,502.0 | 3,572.0 | 3,643.5 |
| Tennant Creek   | Min (TJ/d)     | 0.5     | 0.5     | 0.5     | 0.5     | 0.5     |
|                 | Max (TJ/d)     | 1.9     | 1.9     | 1.9     | 1.9     | 1.9     |
|                 | Average (TJ/d) | 1.3     | 1.3     | 1.3     | 1.4     | 1.4     |
|                 | Total (TJ/a)   | 472.8   | 480.7   | 488.7   | 496.8   | 505.1   |
| Elliott         | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Max (TJ/d)     | 0.2     | 0.2     | 0.2     | 0.2     | 0.2     |
|                 | Average (TJ/d) | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     |
|                 | Total (TJ/a)   | 37.1    | 37.2    | 37.3    | 37.4    | 37.6    |
| Daly Waters     | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Max (TJ/d)     | 8.0     | 8.0     | 8.0     | 8.0     | 8.0     |
|                 | Average (TJ/d) | 5.5     | 5.5     | 5.5     | 5.5     | 5.5     |
|                 | Total (TJ/a)   | 2,025.0 | 2,025.0 | 2,025.0 | 2,025.0 | 2,025.0 |
| Mataranka       | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Max (TJ/d)     | 0.2     | 0.2     | 0.2     | 0.2     | 0.2     |
|                 | Average (TJ/d) | 0.1     | 0.1     | 0.1     | 0.1     | 0.1     |
|                 | Total (TJ/a)   | 50.0    | 50.0    | 50.0    | 50.0    | 50.0    |
| Katherine       | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Max (TJ/d)     | 11.9    | 12.0    | 12.1    | 12.3    | 12.4    |
|                 | Average (TJ/d) | 1.1     | 1.1     | 1.1     | 1.2     | 1.2     |
|                 | Total (TJ/a)   | 409.1   | 413.1   | 417.3   | 421.4   | 425.7   |
| Mt Todd         | Min (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Max (TJ/d)     | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Average (TJ/d) | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |
|                 | Total (TJ/a)   | 0.0     | 0.0     | 0.0     | 0.0     | 0.0     |



|                       |                     | 2011/12         | 2012/13         | 2013/14         | 2014/15         | 2015/16         |
|-----------------------|---------------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Pine Creek            | Min (TJ/d)          | 0.5             | 0.5             | 0.5             | 0.5             | 0.5             |
|                       | Max (TJ/d)          | 7.0             | 7.0             | 7.0             | 7.0             | 7.0             |
|                       | Average (TJ/d)      | 5.4             | 5.4             | 5.4             | 5.4             | 5.4             |
|                       | Total (TJ/a)        | 1,986.0         | 1,986.0         | 1,986.0         | 1,986.0         | 1,986.0         |
| Cosmo                 | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Total (TJ/a)        | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
| Ban Ban Springs       | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Total (TJ/a)        | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
| Darwin City Gate      | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Max (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Average (TJ/d)      | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Total (TJ/a)        | 10.0            | 10.0            | 10.0            | 10.0            | 10.0            |
| Weddell               | Min (TJ/d)          | 0.0             | 0.0             | 0.0             | 0.0             | 0.0             |
|                       | Max (TJ/d)          | 18.5            | 19.1            | 19.7            | 20.3            | 20.9            |
|                       | Average (TJ/d)      | 13.2            | 13.6            | 14.0            | 14.4            | 14.8            |
|                       | Total (TJ/a)        | 4,810.1         | 4,954.4         | 5,103.0         | 5,256.1         | 5,413.8         |
| Channel Island        | Min (TJ/d)          | 9.0             | 9.0             | 9.0             | 9.0             | 9.0             |
|                       | Max (TJ/d)          | 53.6            | 55.2            | 56.8            | 58.5            | 60.0            |
|                       | Average (TJ/d)      | 27.4            | 28.3            | 29.1            | 30.0            | 30.9            |
|                       | Total (TJ/a)        | 10,016.8        | 10,317.3        | 10,626.8        | 10,945.6        | 11,273.9        |
| <b>Pipeline Total</b> | <b>Total (TJ/a)</b> | <b>23,182.8</b> | <b>23,707.0</b> | <b>24,246.1</b> | <b>24,800.5</b> | <b>25,370.6</b> |





### *Alice Springs*

Historic and forecast volumes for the delivery point into the Alice Springs Pipeline are shown in Figure 5.5 below. Gas delivered at Alice Springs is used for electricity generation for domestic, commercial and light industrial end uses. Alice Springs load represented 14.6 per cent of total volumes on the pipeline in 2010/11 and is the third largest load.

The demand profile for Alice Springs delivery point changed in 2003/04 with the full utilisation of the Palm Valley interconnect. Prior to this the AGP only supplied part of the Alice Springs demand.

Alice Springs gas usage exhibits a seasonal load profile with highest demand in the summer months, corresponding with a cooling load. In recent years there has also been a winter load influence, which appears to be driving part of the load increase observed.

While anecdotal, this winter heating load increase appears to correspond with an increase in reverse cycle air conditioners installed as a proportion of all air conditioners in NT, which rose from 4 per cent in 2000 to 16.5 per cent in 2005, at which time the forecast for 2010 was for reverse cycle air conditioners to reach 18.4 per cent in 2010. This rapid increase in the proportion of reverse cycle air conditioners compared to other types of units was also accompanied by a significant increase in the total number of air conditioners installed in NT.<sup>53</sup>

NT Gas' forecast load growth for Alice Springs has been derived by adjusting historic demand growth for expected efficiencies in generating units recently installed by PWC. To calculate the reduction in demand associated with increased efficiency of the new units, NT Gas has calculated the observed demand changes achieved at Channel Island with the installation of units with similar efficiency, and applied this saving to the historic growth trend to give a growth rate of 2 per cent per annum.<sup>54</sup>

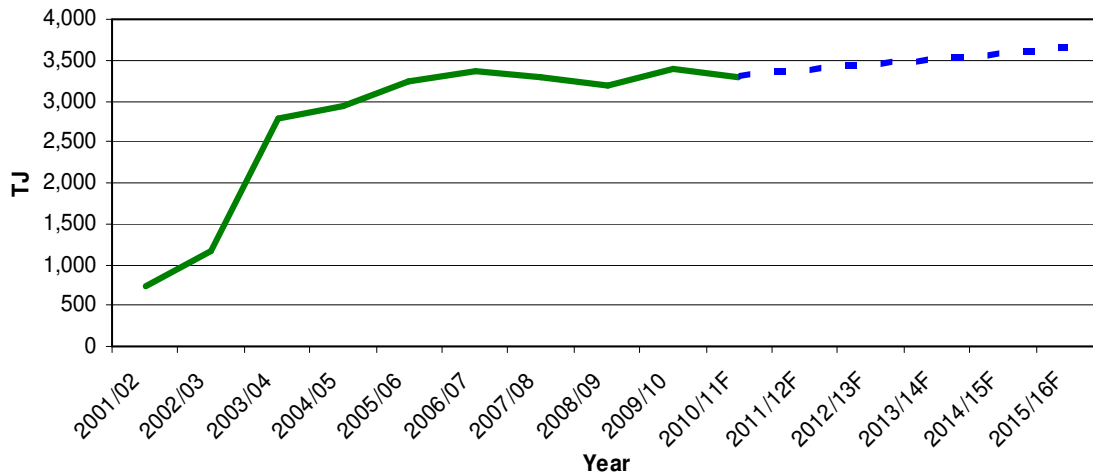
Maximum demand is also forecast to grow at the same rate as volumes over the period.

---

<sup>53</sup> Energy Efficient Strategies 2006, *Status of air-conditioners in Australia: updated with 2005 data: Report for NAEDEC 2005/09 (updated)*, January, p 51

<sup>54</sup> NT Gas adjusted the 2010/11 starting point of the forecast for Alice Springs as the forecast provided by PWC did not appear consistent with trends for demand at this site.

**Figure 5.5 – Alice Springs delivery point volume forecast**

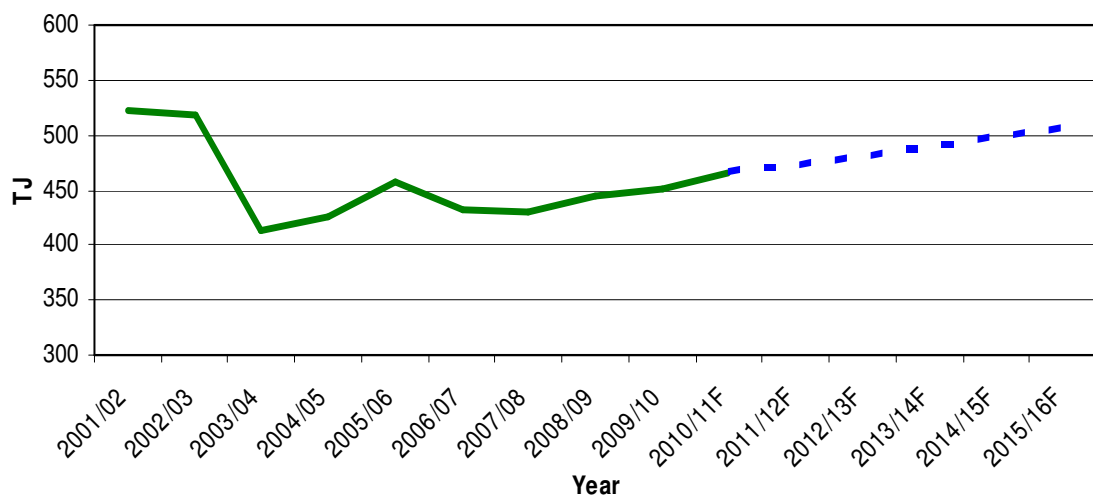


### *Tennant Creek*

Historic and forecast demand for the Tennant Creek delivery point is shown in Figure 5.6 below. Similar to Alice Springs, gas delivered to Tennant Creek is used for electricity generation for domestic, commercial and light industrial end uses and exhibits a seasonal load profile, with a recognisable winter heating load. Tennant Creek demand represented 2.1 per cent of total volumes on the pipeline in 2010/11.

The decline in demand in 2003/04 corresponds with the closure of the Tennant Creek concrete railway sleeper factory following the completion of the Alice Springs to Darwin rail link. Other drivers of demand at this delivery point are very similar to Alice Springs. NT Gas has derived its forecast for this delivery point based on recent trend growth of an average of 1.7 per cent per annum, using PWC's 2010/11 forecast demand for this delivery point as the starting point for the forecast.

**Figure 5.6 – Tennant Creek delivery point volume forecast**





### *Elliott*

The Elliott delivery point load profile fluctuated significantly over the earlier access arrangement period, mainly due to fuel substitution. Elliott load is very minor compared with total load for the pipeline (0.2 per cent in 2010/11).

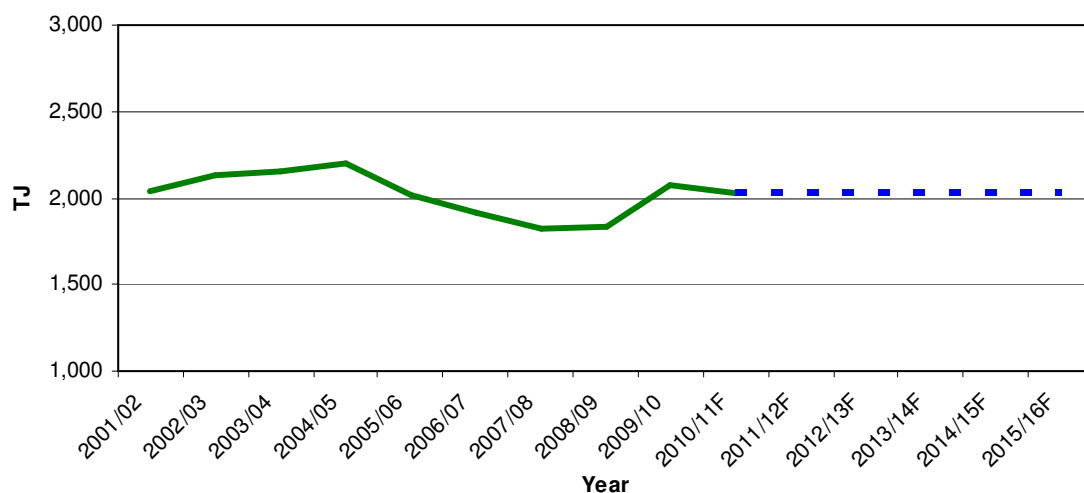
A step change in 2008/09 demand was due to the installation of new generation equipment and an increase in the proportion of electricity load generated using gas instead of diesel. This is largely a function of the increased availability of gas with the connection of the Bonaparte Gas Pipeline in 2009/10. Generation units at Elliott are currently operating at capacity and NT Gas has forecast demand at this delivery point to remain stable.

### *Daly Waters*

Daly Waters is an offtake to the MacMarthur River Mine and exhibits a relatively steady load. Historic fluctuations in demand correlate with mining activity. This delivery point represented 8.9 per cent of total volumes on the pipeline in 2010/11.

NT Gas has assumed a steady load at this delivery point over the access arrangement period with no growth, as shown in Figure 5.7 below. NT Gas considers that this is a reasonable assumption given the relatively flat average load for the delivery point over the past ten years, despite significantly changes in the resources industry.

**Figure 5.7 – Daly Waters delivery point volume forecast**



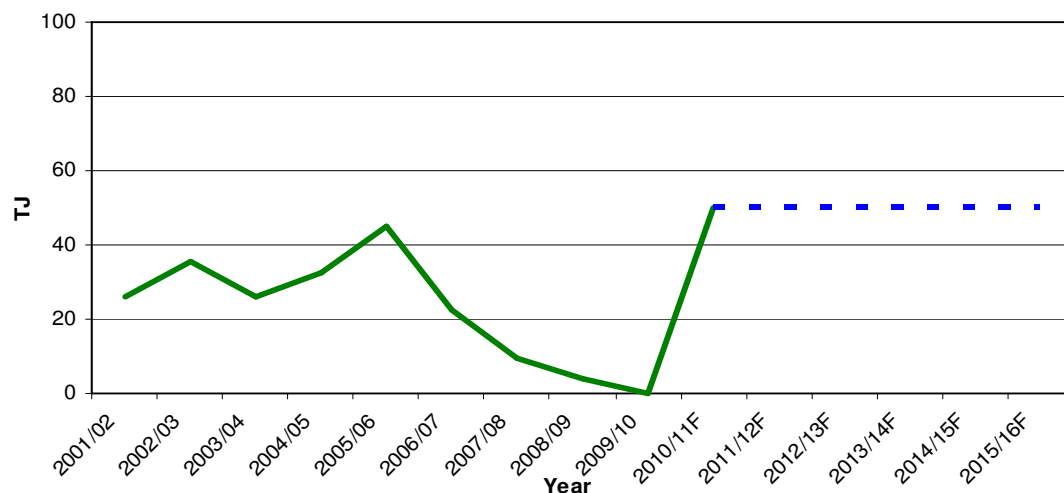
### *Mataranka*

Mataranka offtake supplies a local lime plant to fuel a kiln. Demand over the earlier access arrangement period fluctuated due to the lack of availability of gas and a dual fuel capability at the site. Demand is forecast to return to previous levels in 2010/11 when gas again became available for supply at Mataranka.



NT Gas forecasts demand at this delivery point (which made up only 0.2 per cent of 2010/11 demand) to be stable over the access arrangement period at 2010/11 levels, without further disruptions or fuel substitutions due to the availability of gas.

**Figure 5.8 – Mataranka delivery point volume forecast**

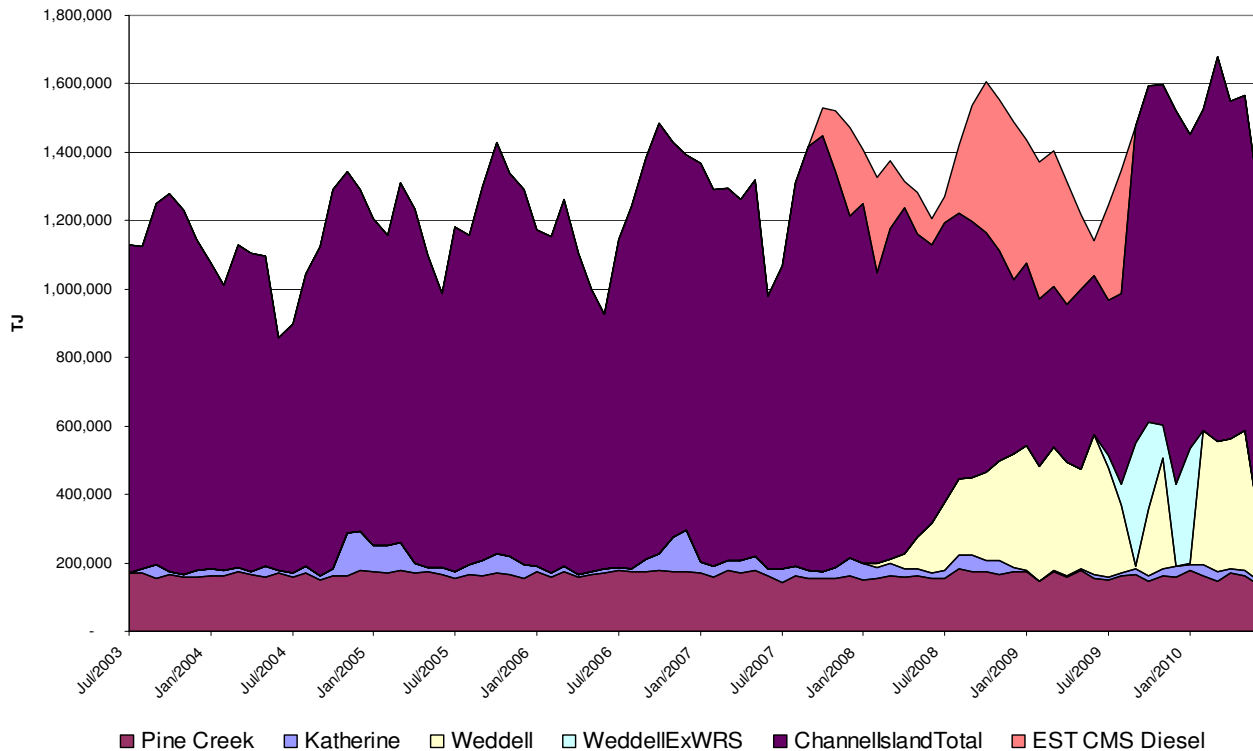


#### *Katherine/Darwin transmission system*

The Katherine, Pine Creek, Weddell and Channel Island delivery points exclusively supply gas for electricity generation for the Katherine/Darwin transmission system. It is therefore important to consider these delivery points essentially as part of a broader demand group, related to electricity generation in the north of NT. This system makes up 74 per cent of demand on the pipeline in 2010/11.

Total seasonal demand for these delivery points is shown in Figure 5.9 below. Figure 5.9 also shows substitution from diesel at Channel Island and at Weddell (which sourced alternate gas over the supply shortfall period from the Wickham Point Pipeline).

**Figure 5.9 – Darwin/Katherine transmission system seasonal demand profile**



This graph shows the complexity of gas demand across the delivery points, and the different utilisation of generating units as follows:

- Pine Creek units contribute steady base load delivered by a third party generator under contract to PWC. Gas demand therefore does not change significantly over the period;
- Katherine units are largely used as peaking load, and can be seen at the bottom of the graph showing intermittent gas use reflecting this duty;
- Channel Island units contributed steady base load over the majority of the earlier access arrangement period, however with the commissioning of more efficient generating units at Weddell in 2008/09-2010/11, some gas demand at Channel Island is displaced by demand at Weddell units; and
- Weddell units, upon commissioning, being used in base load generation in place of some Channel Island units.

This information has been used to derive a forecast for each delivery point contributing to the Katherine/Darwin transmission system as follows.



### Pine Creek

Demand at this delivery point made up 8.8 per cent of total 2010/11 demand. Reflecting the historically very stable demand at this delivery point, NT Gas forecasts demand at this point to remain stable with zero growth.

### Katherine

Katherine gas volumes make up 1.8 per cent of total 2010/11 demand. To derive its volume forecast for Katherine, NT Gas has assumed that the Katherine generating facilities continue to operate in line with their historical operation as a peaking facility. This assumption is consistent with information available to NT Gas from PWC for 2010/11, provided as part of their short term demand forecasts. Using the volumes provided by PWC for 2010/11, NT Gas has then forecast growth for this point based on average historic demand growth, of 1 per cent per annum.

Maximum demand at this site is expected to increase in 2010/11 with the completion of the Katherine Meter Station Upgrade. This upgrade substantially increases the capacity at Katherine gas meter station, and is required to provide for the upgrade in the generation at the site. The maximum demand at this site has been based on the required capacity of this site for 2010/11 as advised by PWC to meet this demand. Maximum demand is forecast to grow at the same rate as volumes over the period starting from the upgraded maximum demand value advised by PWC.

### Weddell

The Weddell delivery point was commissioned in 2007. The historic demand has shown a step increase with the staged commissioning of two generating units, which are now both in service. The forecast reflects an increase in utilisation of these more efficient units and the displacement of gas load from Channel Island, with a forecast growth of 3 per cent per annum, reflecting the trend in total gas demand growth for the Darwin/Katherine transmission system over the earlier access arrangement period.

Maximum demand is forecast to grow at the same rate as volumes over the period using the average of the maximum demand over the past two years as the 2010/11 starting point for the forecast.

### Channel Island

Channel Island is the dominant load for this pipeline, with 42.9 per cent of 2010/11 volumes for the pipeline delivered to this point. As discussed above, volumes at this supply point were significantly impacted between September 2007 and August 2009 by a shortfall in gas, where generation was supplemented with significant amounts of diesel fuel.

In recent times, gas demand at this delivery point has been displaced by demand at Weddell, however PWC is currently expanding Channel Island generation capacity so demand at this point is expected to continue to grow, albeit from a slightly lower base (see discussion of Channel Island meter station upgrade project at Attachment D in the capital expenditure chapter). In line with the trend in total gas demand growth for the Darwin/Katherine transmission system over the earlier access arrangement period, NT



Gas forecasts demand at Channel Island to grow by 3 per cent per annum over the access arrangement period.

While the number of power generation units at this site is currently being expanded (with an associated capital expenditure project discussed in section 6.2.1 below), the required electrical infrastructure to distribute the electricity from the island is not being upgraded. The result is that the maximum demand at this site is expected to remain in line with historical demand. NT Gas has derived this value from the average of the five highest maximum demand values observed over the earlier access arrangement period, and forecast an annual growth rate in line with the expected growth in volumes.

This maximum demand value of 60TJ/day reached in 2015/16 reflects the gas demand to service PWC's maximum electricity transfer capacity off Channel Island, which is not expected to change during the access arrangement period.

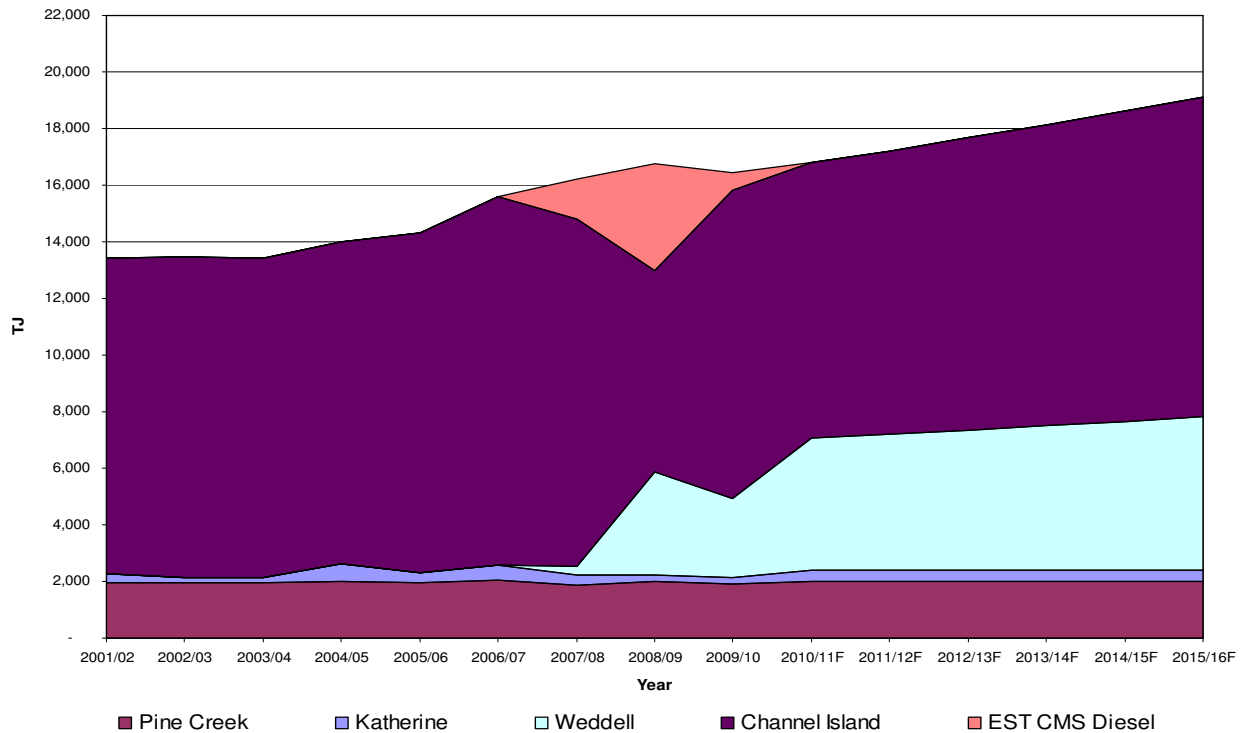
#### Total forecast Darwin/Katherine transmission system demand

Total forecast Darwin/Katherine transmission system demand is shown in Figure 5.10 below, shown with demand annualised to smooth demand peaks and more clearly show underlying demand trends. In total, NT Gas forecasts the Darwin/Katherine transmission system gas demand to grow by 2.6 per cent per annum. This is a slight decrease from the growth rate in the earlier access arrangement period of 3.2 per cent per annum, reflecting the increased efficiency of newer generating units installed at Channel Island, Katherine and Weddell, which can be as much as 10 per cent more efficient than the generating units they replace.

NT Gas considers that this forecast is arrived at on a reasonable basis, and represents the best forecast or estimate possible in the circumstances.



**Figure 5.10 – Forecast gas demand for the Darwin/Katherine transmission system by delivery point**



### *Mt Todd*

The Mt Todd delivery point notionally supplies a mine that ceased operation at the start of the earlier access arrangement period. NT Gas has forecast no volumes to be delivered at Mount Todd, reflecting demand at this delivery point since 2006/07.

### *Cosmo Howley*

The Cosmo Howley lateral supplied by this delivery point was decommissioned in 2008. No volumes are forecast for this delivery point.

### *Ban Ban Springs*

Ban Ban Springs operated as a delivery point in 2008/09 and 2009/10 with the commissioning of the Bonaparte Gas Pipeline by providing initial line pack. NT Gas forecasts no volumes to be delivered to this point over the access arrangement period as the point now operates as a supply point.

### *Darwin City Gate*

Gas delivered to the Darwin City Gate supplies the Darwin Distribution System for commercial and light industrial users. Demand at this delivery point is low (0.4 per cent of 2010/11 demand) and is forecast to remain steady at 10TJ/annum.





### *System use gas*

System use gas is gas used to operate:

- water bath heaters;
- instrumentation; and
- Compressors.

Depending on the location of metering facilities in relation to facilities using system use gas, the volumes may or may not be included in delivered gas volumes reported in Table 5.2. Some system use gas volumes, such as gas used to operate the compressor in the earlier access arrangement period, were metered and are not included in delivered gas volumes in Table 5.2. System use gas costs are recovered from users of the pipeline under contract as a percentage of total gas delivered.

System use gas in 2010/11 is less than 0.1 per cent of total gas delivered and is not included in forecast volumes in Table 5.5.

### *Total gas demand*

NT Gas considers that its volume and demand forecasts included in this chapter are arrived at on a reasonable basis, and represent the best forecast or estimate possible in the circumstances. NT Gas has utilised available up-to-date information to derive these forecasts, and has supported forecasts with the primary information referenced throughout the chapter. Referenced documents are included in supporting documents to this submission.

## 5.2.4 Forecast user numbers

NT Gas has forecast user numbers for each delivery point for the access arrangement period. These are provided in Table 5.6 below and show that the only projected user for the pipeline over the period is PWC.

***Table 5.6 – Forecast user numbers by delivery point over the access arrangement period***

| Delivery points | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|-----------------|---------|---------|---------|---------|---------|
| Alice Springs   | 1       | 1       | 1       | 1       | 1       |
| Tennant Creek   | 1       | 1       | 1       | 1       | 1       |
| Elliott         | 1       | 1       | 1       | 1       | 1       |
| Daly Waters     | 1       | 1       | 1       | 1       | 1       |
| Mataranka       | 1       | 1       | 1       | 1       | 1       |
| Katherine       | 1       | 1       | 1       | 1       | 1       |
| Mt Todd         | 0       | 0       | 0       | 0       | 0       |
| Pine Creek      | 1       | 1       | 1       | 1       | 1       |



|                  |   |   |   |   |   |
|------------------|---|---|---|---|---|
| Cosmo            | 0 | 0 | 0 | 0 | 0 |
| Ban Ban Springs  | 0 | 0 | 0 | 0 | 0 |
| Darwin City Gate | 1 | 1 | 1 | 1 | 1 |
| Weddell          | 1 | 1 | 1 | 1 | 1 |
| Channel Island   | 1 | 1 | 1 | 1 | 1 |

As discussed above in relation to historic user numbers, users in addition to PWC have in the past only contracted over short periods of time, usually associated with:

- The limited availability of firm contracting arrangements;
- Historic limited availability of gas and capacity to support longer term arrangements; and
- The nature of the users, which are generally shorter term mining operations.

Despite gas availability improving with the connection of the Bonaparte Gas Pipeline, NT Gas expects this trend to continue, as the other drivers for shorter term contracts remain largely in place. Importantly, similar to the last period, the full capacity of the pipeline is again expected to be fully contracted to PWC for the term of the access arrangement. This will limit NT Gas' ability to offer firm haulage contracts, as discussed above in chapter 2.

While NT Gas is currently marketing transportation services on the pipeline, at this stage there are no users other than PWC on the pipeline, and there are no transportation agreements currently under negotiation which would allow NT Gas to confidently forecast an additional user on the pipeline at any particular delivery point during the access arrangement period. In this context, NT Gas has no basis for assuming that there will be additional users on the pipeline at any given delivery point, even if it is likely that at some stage over the access arrangement period additional users will contract to use the pipeline (as they did in the previous period).

### 5.2.5 Forecast capacity and utilisation

Forecast capacity has been calculated on the same basis as historic capacity, and is described in section 5.1.3 above.

Utilisation of the pipeline has been forecast using an estimate of the non-coincident maximum demand for all delivery points divided by the forecast capacity of the pipeline. The estimate of non-coincident demand has been derived from recent flow data extrapolated for the forecast years with an annual growth rate matching forecast volume growth.



**Table 5.7 – Forecast pipeline capacity and utilisation over the access arrangement period**

|                                  | Units  | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|----------------------------------|--------|---------|---------|---------|---------|---------|
| Pipeline capacity                | TJ/day | 104.0   | 104.0   | 104.0   | 104.0   | 104.0   |
| Utilisation of pipeline capacity | %      | 79      | 80      | 82      | 84      | 86      |



## 6 Capital expenditure

This chapter sets out capital expenditure undertaken in the earlier access arrangement period and forecast capital expenditure for the access arrangement period, and provides explanations and justifications for actual and forecast capital expenditure by reference to the Rules.

For the purposes of the access arrangement revision proposal NT Gas classifies its capital expenditure according to driver as follows:

- *Expansion* capital expenditure, which is required to expand the capacity of the pipeline to meet demand both within the access arrangement period and beyond;
- *Replacement* capital expenditure, which is required to maintain the integrity of the pipeline and includes items such as replacement of instrumentation (for example metering, telemetry, remote terminal units), pipeline hardware (for example pipes, meter valves, regulators and fittings), site capital improvements (for example fencing and security), and specialised major spares; and
- *Non-system* capital expenditure, which relates to capital required for replacement of items such as office furniture and computer equipment.

These classifications are identical to those used in the earlier access arrangement period to ensure consistency when comparing actual expenditure against the forecasts used to derive tariffs in the earlier access arrangement period, and comparing past and future expenditure in this proposal.

NT Gas does not use these classifications in its actual accounting and therefore some judgement has been applied in categorising historic and forecast expenditure into these classifications.

### 6.1 Rules governing conforming capital expenditure

Rule 79(1) specifies that capital expenditure

... must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The capital expenditure must also be justifiable on a ground stated in subrule (2).

Rule 79(2) goes on to set out three main subrules for capital expenditure as follows:

- (a) the overall economic value of the expenditure is positive; or
- (b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or
- (c) the capital expenditure is necessary:



- (i) to maintain and improve the safety of services; or
- (ii) to maintain the integrity of services; or
- (iii) to comply with a regulatory obligation or requirement; or
- (iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)

The AER's discretion under this rule is limited such that the AER must not withhold its approval of capital expenditure if it is satisfied that it complies with the requirements of the law and is consistent with Rule 79. All forecasts and estimates must also comply with Rule 74.

## **6.2 Capital expenditure over the earlier access arrangement period**

Table 6.2 compares forecast capital expenditure approved by the ACCC in its 2002 Final Decision with NT Gas' actual and estimated capital expenditure over the earlier access arrangement period in constant dollar terms (2009/10 dollars). The ACCC's 2002 Final Decision approved forecast capital expenditure as proposed by NT Gas in its revised proposal made in response to the ACCC's Draft Decision.

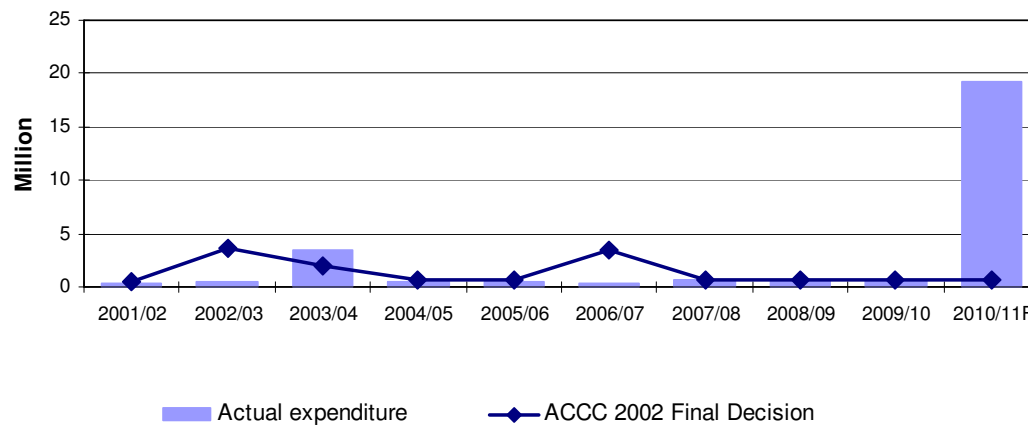
NT Gas' total capital expenditure over the earlier period is expected to be \$26.8 million. This is \$13.4 million above that approved by the ACCC for the period. These deviations are attributable to variations from forecast as follows:

- Expansion capital expenditure of \$7.4 million where no expenditure was previously forecast in this category;
- Replacement capital expenditure \$11.2 million above the earlier access arrangement allowance; and
- Non-system capital expenditure \$5.2 million below the earlier access arrangement allowance.

While total incurred capital expenditure varies significantly from that forecast in 2001, as shown in Figure 6.1, these differences are largely limited to the final year of the access arrangement period, where NT Gas is undertaking an enhanced integrity program. A breakdown of variances by capital expenditure driver is provided in the following section.



**Figure 6.1 – Comparison between forecast and actual capital expenditure over the earlier access arrangement period**



### 6.2.1 Expansion capital expenditure

NT Gas did not forecast any expenditure in the expansion category for the earlier access arrangement period. NT Gas did, however, undertake three expansion projects during the period.

In 2009/10, NT Gas removed check valves along the pipeline south of Ban Ban Springs at the cost of \$0.36 million. This expenditure was necessary to allow southbound flow on the pipeline after the connection of the Bonaparte Gas Pipeline, to ensure delivery of gas entering the pipeline at Ban Ban Springs to all points along the pipeline. This expenditure was therefore necessary to ensure that NT Gas could continue to provide pipeline services south of Ban Ban Springs after the primary source of gas for the pipeline changed to the Blacktip gas field.

NT Gas is also undertaking a project to upgrade the capacity of the Katherine Meter Station following a request from PWC to undertake the project. Details of the project are provided in Box 6.1 below.



### **Box 6.1 – Katherine Meter Station Upgrade**

#### **Katherine Meter Station Upgrade**

##### *Background*

The upgrade of the Katherine Meter station is driven by the request by PWC to support an increase in the capacity of the Katherine generating facilities from 18MW to 36MW. This involves increasing the capacity of the meter station from 3,900sm<sup>3</sup>/h to 17,400sm<sup>3</sup>/h.

##### *Project summary*

The meter station upgrade involves replacement of the existing duty and stand-by runs (including filters, water bath heaters, regulators and meters) to meet new demand requirements.

A requirement of AS2885 and other standards referenced in AS2885 is that where an upgrade is made to existing meter station facilities that may not be compliant with enhanced obligations in the standard (but are grandfathered under the standard), those facilities must be brought into full compliance with the standard at the time of upgrade. This requirement is driving some of the expenditure at the site, in particular in relation to the existing electricity supply under AS/NZS 3000:2007 (Standard for Wiring Rules) and related Australian Standards, Hazardous area classifications under AS2430.3.4-2004 (Classification of Hazardous Areas - Examples of Area Classification Flammable Gases) and certification of equipment for use in hazardous areas under AS2381.1 2005 (Electrical Equipment for explosive atmospheres Part 1 - General Requirements).

Where possible, NT Gas is utilising and redeploying assets currently in use at the site, though the ability to do this while remaining compliant with enhanced requirements under AS2885 is limited. NT Gas has identified an opportunity to redeploy the filters for use in the standby run, for example.

##### *Project costings and timing*

The Katherine Meter Station Upgrade project costings and timings are shown in Table B6.1 below. Further information on the derivation of the cost estimates for this project can be found in the Asset Management Plan provided at Attachment C to this submission.

**Table B6.1 – Katherine Meter Station Upgrade project costings and timings**

| <b>\$'000 (2009/10)</b>         | <b>2010/11</b> |
|---------------------------------|----------------|
| Katherine Meter Station Upgrade | 7,487          |

##### *Justification under National Gas Rules*

This project is justified under Rule 79(2)(b) as the incremental revenue to be generated from this expansion exceeds the present value of the capital expenditure.

NT Gas has calculated that the net present value of this project is positive using the forecast capacity tariff in the revised access arrangement over the economic life of this asset. Details of this calculation are provided at Attachment E.

NT Gas considers that this project therefore satisfies the requirements of Rule 79(2)(b) as conforming capital expenditure.

A further expansion project in 2010/11 is the Channel Island meter station upgrade. This project, while increasing the capacity of the delivery point, has different drivers to the Katherine Meter Station upgrade and is justified under Rule 79(2)(c), as described in confidential Attachment D, related to security of electricity generation at the site.

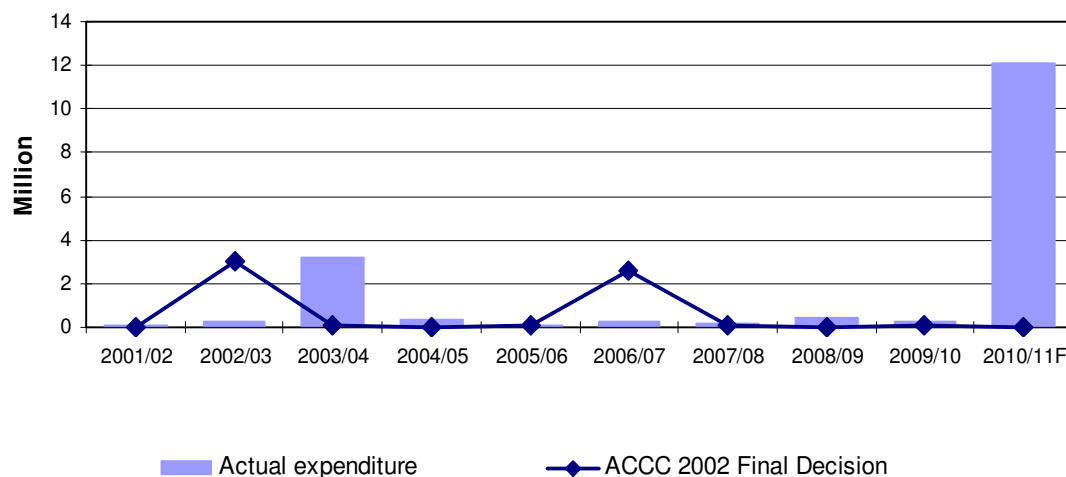


The upgrade involves providing an interconnection to the existing station from which gas will be supplied to a new meter and regulating station upstream of the new generation units. NT Gas will also provide resources to attend design workshops, safety management studies composed of HAZOP studies and risk assessments, and labour and supervision for mechanical, civil and electrical works associated with the interconnection in the existing station. Project expenditure is forecast at \$0.64 million in 2010/11.

## 6.2.2 Replacement capital expenditure

Replacement capital expenditure over the earlier access arrangement period compared to the annual amounts approved by the ACCC are shown in Figure 6.2 below and at Table 6.2 at the end of this chapter.

**Figure 6.2 – Replacement capital expenditure comparison to forecast over the earlier access arrangement period**



As can be seen from Figure 6.2 above, up until 2010/11, replacement capital expenditure was below forecast. This was primarily due to two main factors:

- a delay of one year in the proposed SCADA upgrade project, scheduled for 2002/03 but undertaken in 2003/04 and 2004/05;
- not undertaking the Mereenie looping project that was scheduled for 2006/07 at a forecast cost of \$2.5 million (\$2009/10). At the time of making the earlier access arrangement proposal, Mereenie was expected to continue to be a dominant gas source, and constraints were forecast in the delivery of gas from the Mereenie gas field that would undermine supply security for users along the pipeline. The decision not to proceed with this project was made when gas reserves from the Mereenie fields were found to be depleting, and the main user of the pipeline sourced alternative gas supply from the Blacktip gas field to replace supply from the Mereenie field. Based on the current profile of gas transportation on the



pipeline, if built, the Mereenie loop would be a redundant asset and therefore the decision not to proceed with this project was prudent.

Offsetting these savings is an increase in the cost of the SCADA upgrade undertaken in 2003/04 and 2004/05 from a forecast of \$2.2 million (\$2009/10), with actual expenditure being \$2.7 million (\$2009/10).

The increase in costs associated with the SCADA upgrade were as a result of some expenditure being undertaken at this time on upgrading the communications system from a radio to a satellite system. These costs (which would otherwise be categorised as non-system expenditure) were included in SCADA upgrade costs at the time and are not able to be isolated from these costs without significant analysis of historical records.

NT Gas considers that its replacement capital expenditure over the access arrangement period satisfies the requirements of Rule 79 and should be rolled into the opening capital base for the period. All projects were developed through the planning processes described in Chapter 3 on a needs basis, and were subject to rigorous review by PWC under existing contractual arrangements. Relevant Operating Cost Request forms for each major project are provided in the supporting documents to this submission.

In addition, all significant projects undertaken were approved by the ACCC in 2002 for inclusion in the capital base as forecast conforming capital expenditure.

### *Enhanced integrity works*

Significant integrity issues have been identified with the pipeline that NT Gas consider, based on risk assessment, require immediate rectification. An enhanced integrity works program has therefore been established to address immediate integrity issues, to be undertaken through a special project delivery structure over 2010/11 and 2011/12. Ongoing enhanced integrity works are also required throughout the access arrangement period (discussed further in relation to forecast capital and operating expenditure).

The integrity works program has been established after detailed internal and external assessment of the future monitoring and maintenance needs of the pipeline. This assessment involved a number of integrity assessments and studies, including:

- Intelligent pigging of the Mereenie Spurline and Palm Valley to Mataranka sections of the pipeline in 2008/09 which revealed considerable metal loss and sleeve disbondment that was not evident in the previous pigging survey (undertaken approximately 10 years previously);
- Direct Current Voltage Gradient (DCVG) surveys undertaken progressively throughout the earlier access arrangement period on a five yearly cycle that uncovered significant problems with pipeline coating with cracks and other coating defects not detected through intelligent pigging; and



- Cathodic protection survey which found degradation in the CP protection of the pipeline due to degradation of the pipeline coating and the age of the CP system.

This data was then analysed both internally and externally by engineering consultants to assist preparing a preventative maintenance program for an ageing pipeline. Relevant studies and reports include:

- IONIK integrity report completed – 2009;
- Gippsland Cathodic Protection Services report – 2010; and
- Rosen intelligent pigging reports – 2008 and 2009.

In addition, the Channel Island spurline is unpiggable, and continued reliance on DCVG is considered undesirable due to the age of the pipeline and results of recent surveys. NT Gas therefore proposes replacement of part of the spurline to allow in line integrity inspections. The changing use of the pipeline towards net southbound flow also means that significant expenditure is required to ensure that the mainline remains piggable south of Ban Ban Springs.

#### Delivery of enhanced program

The scope of the immediate enhanced integrity works program exceeds NT Gas' internal project delivery capabilities. NT Gas considers these projects are essential for compliance with existing technical regulatory obligations and to ensure the ongoing integrity of the pipeline. NT Gas has therefore set up a special project delivery structure to ensure that it can deliver the projects, and at the same time achieve efficiencies in project delivery that may not be achievable at another time, or through works carried out over a longer period.

NT Gas has appointed a Special Projects Manager and a Special Projects team to carry out the immediate integrity works program. This project structure allows NT Gas to significantly ramp up its project delivery capabilities over the short term, while allowing a return to normal operations after completion of the program.

As discussed further in Chapter 9 in relation to historic operating expenditure, NT Gas has experienced significant human resourcing issues over the earlier access arrangement period, particularly driven by its relatively remote location and the transferability of skills to the mining and energy sectors. The current slight downturn in demand for labour resources has allowed NT Gas to recruit sufficient short term resources to schedule the delivery of the forecast program of works. The expected return of mining activity to the historically high levels experienced before the global financial crisis may jeopardise NT Gas' ability to execute the required projects if they were deferred to later in the access arrangement period, as NT Gas expects that it would again struggle to recruit and retain sufficient resources to undertake the program.

It is expected that the special project structure will also deliver efficiencies through utilisation of professional project management expertise and scheduling of works, though these are difficult to isolate and quantify. Project costings discussed in the



remainder of this section assume project delivery within the special program, and may be affected if the timing of projects changes and they need to be delivered at a later date. It should also be noted that delay in the execution of some key integrity projects may impact AGP's allowable operating pressure, impacting customer activity. It may also undermine NT Gas' ability to fulfil its contractual obligations.

While specific integrity projects are being delivered over 2010/11 and 2011/12 through the special project structure, there is an ongoing need to increase integrity works on the pipeline, which is reflected in forecast capital and operating expenditure in the access arrangement period. As a result, some projects discussed here in relation to special projects continue in the later years of the access arrangement period, delivered through more routine project structures. In particular, projects such as the sleeve replacement program and the cathodic protection upgrade must be maintained to address emergent issues in the pipeline. These are discussed further in the forecast capital and operating expenditure sections.

#### Integrity projects

The total capital expenditure forecast for enhanced integrity works is \$18.2 million, of which \$10.7 million is scheduled for 2010/11. A description of the key projects making up the capital expenditure program for 2010/11, is set out in the boxes below as follows:

- Channel Island meter replacement - Box 6.2
- Channel Island Piggability Project - Box 6.3
- Replacement of Elliot heaters - Box 6.4
- Southbound piggability project - Box 6.5
- Cathodic protection upgrade stage 2 - Box 6.6
- Hazardous area assessment and equipment replacement - Box 6.7
- Palm Valley filtration and slam-shut - Box 6.8
- Heat Shrink sleeve replacement - Box 6.9
- Below ground station pipework recoating - Box 6.10

Together, these projects make up 98 per cent of total integrity program capital expenditure to be undertaken in 2010/11 and 2011/12, as well as 96 per cent of integrity program capital expenditure undertaken in 2010/11. Details of all projects above \$200,000 making up the enhanced integrity program are described here.



### **Box 6.2 – Channel Island meter replacement**

#### **Channel Island meter replacement**

##### *Background*

The metering on the pipeline off-takes is generally by orifice meter. The accuracy of orifice meters can be relatively poor and they are sensitive to wear and fouling, and have a tendency to under-read should the plates become worn or even slightly contaminated. At best these meters would be +/- 1% accurate, and experience suggests that +/- 2% is a reasonable expectation with errors up to +/- 5% possible.

NT Gas does not consider this level of accuracy to be appropriate due to the volume of gas throughput, particularly where there are third party users on the pipeline. As ultrasonic metering is in place at Ban Ban Springs inlet station, the imbalance in the accuracy of fiscal metering will contribute to greater unaccounted for gas. Current technology (ultrasonic or coriolis metering) would improve accuracy to +/- 0.1% and increase reliability.

##### *Project summary*

Replacement of two existing orifice plate meters at Channel Island with Ultrasonic meters.

The ultrasonic meters provide the lowest operation and maintenance costs going forward as they have no moving parts. These meters provide the required turn down ratios (the ratio of minimum to maximum flow rate) which in some cases are as much as 1 to 100.

##### *Project costings and timing*

The Channel Island meter replacement costings and timings are shown in Table B6.2 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.2 – Channel Island meter replacement costings and timings**

| <b>\$'000 (2009/10)</b>          | <b>2010/11</b> |
|----------------------------------|----------------|
| Channel Island meter replacement | 214            |

##### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(ii) and (iii), as, while metering accuracy requirements are not subject to national standards, they are important features of the supply, delivery and transportation contracts entered into between producers, shippers and the gas transportation companies. NT Gas considers that improving metering accuracy at Channel Island is essential to ensure accurate metering of gas usage at this delivery point to ensure appropriate allocation of unaccounted for gas (UAG) to all users of the pipeline. In addition, the total accuracy of metering systems on a pipeline is ultimately reflected in the accuracy of linepack and UAG. It can also affect the accuracy of emissions reported under the requirements of the National Greenhouse and Energy Reporting Act 2007.

##### *Linkages*

As part of the Katherine Meter Station Upgrade the existing orifice plate meters will be replaced with ultrasonic meters. NT Gas has given consideration to replacing the Tennant Creek orifice metering system, however the volumes through this site are modest and hence the impact of errors are less significant. It is not expected that meter change outs will be required at the pipeline inlet stations at Palm Valley and Mereenie based on current forecast flows.



### **Box 6.3 – Channel Island piggability project**

#### **Channel Island piggability project**

##### *Background*

A 12 kilometre spurline runs from Darwin City Gate to Channel Island Meter Station with approximately 800 metres of 8" heavy wall pipe installed on the bridge crossing towards the end of the section. This pipeline is critical to Darwin as it feeds major power generation facilities.

The 12 kilometre spurline is currently unpiggable with intelligent inline inspection tools due to the dual diameter construction. Thus, the levels of corrosion (leading to loss of wall thickness) are currently hard to quantify. Whilst other integrity assessment methods are utilised such as DCVG surveys, these methods can only detect potential areas of metal loss, compared to intelligent pigging that detects actual metal loss. Further, NT Gas has uncovered corrosion in other parts of the pipeline not detected through DCVG surveys and despite cathodic protection.

##### *Project summary*

Several options are available including continuing to rely on identification of corrosion through physical inspection, DCVG and cathodic protection surveys, and replacement of the pipeline section to make the whole section of the pipeline piggable.

The continued reliance on DCVG is considered undesirable, and the replacement of the 8" section of pipeline that crosses the bridge will ensure the ongoing integrity of this critical asset.

The project involves replacement of the pipeline at the bridge crossing with 12" pipe, to allow the entire section of pipeline to be pigged as a single section. This project will also see upgrades in Darwin City Gate with the addition of a pig launcher and Channel Island meter station with a pig receiver, filter and associated valving.

##### *Project costings and timing*

The Channel Island piggability project costings and timings are shown in Table B6.3 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.3 - Channel Island piggability project costings and timings**

| <b>\$'000 (2009/10)</b>            | <b>2010/11</b> | <b>2011/12</b> | <b>Total</b> |
|------------------------------------|----------------|----------------|--------------|
| Channel Island piggability project | 3,262          | 3,223          | <b>6,485</b> |

##### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i)-(iii), as it is required to ensure the ongoing safety and integrity of the pipeline, as required under AS2885.3 (described in more detail in Chapter 3 above).



#### **Box 6.4 – Replacement of Elliott heaters**

##### **Replacement of Elliott heaters**

###### *Background*

During the upgrade of the Elliott Power station in 2007, the maximum delivery requirements of the gas delivery station were increased significantly. The Elliott delivery station is now not capable of delivering gas to the specification temperature.

The recent change in gas quality from Amadeus Basin gas to Blacktip gas may result in the formation of liquid hydrocarbons at the Elliott delivery station, which would breach current contractual requirements. As a result heaters are required to prevent hydrocarbon liquid dropout.

###### *Project summary*

Replacement of the current catalytic heater at Elliott delivery station with a 2 X 10KW heater system to ensure that the delivery temperature is maintained above dewpoint at this remote location.

###### *Project costings and timing*

The replacement of the Elliott heaters project costings and timings are shown in Table B6.4 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.4 – Replacement of Elliott heaters project costings and timings**

| <b>\$'000 (2009/10)</b>            | <b>2010/11</b> |
|------------------------------------|----------------|
| Replacement of the Elliott heaters | 428            |

###### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(iii), to ensure ongoing compliance with NT Gas' obligations to meet its contract specified quality specification.

#### **Box 6.5 – Southbound piggability project**

##### **Southbound piggability project**

###### *Background*

The change in majority supply, from the Amadeus to the Blacktip gas field, will result in majority southbound flows on the AGP between Ban Ban Springs and Palm Valley. This requires the pipeline to be pigged in the reverse direction compared to pipeline design. In addition, southbound flows are expected to be lower than required for effective metal-loss pigging. It will therefore be necessary to create a pressure/flow regime suitable for pigging.

###### *Project summary*

Existing pigging facilities designed for northbound flow will need to be modified to support southbound pigging. To achieve this, it will be necessary to modify the 'northbound' scraper launchers south of Ban Ban Springs to enable them to be used for receiving southbound pigs. This arises because of the difference in geometry between a pig launcher and receiver and has the potential to allow a pig to lose drive prior to fully entering the trap. The modification essentially creates a receiver out of what is currently a launcher to ensure that the pig is fully 'home' and doesn't obstruct valving which is necessary to isolate the gas from the receiver in order to retrieve the pig. The aim is to make the pipeline bi-directional so that in the future, if flows revert to a northerly direction again, pigs can be sent in either direction.

Adjustments are also required to the in-launcher pigging dust filters, which are custom fitted to the existing launchers and will now have to be refitted to the receivers.





Additionally, to facilitate pigging in the southern direction a flow control skid is required to lower the pressure in the downstream pipeline thereby increasing gas velocity and allowing intelligent pigs to traverse the pipeline. This option minimises any potential impact on the northern delivery points.

*Project costings and timing*

The Southbound piggability project costings and timings are shown in Table B6.5 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.5 – Southbound piggability project costings and timings**

| \$'000 (2009/10)               | 2010/11 | 2011/12 | Total |
|--------------------------------|---------|---------|-------|
| Southbound piggability project | 267     | 161     | 429   |

*Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i) and (iii), as periodic integrity surveys are a requirement of AS2885 and NT Gas' pipeline licence and are not possible without modification of current pigging infrastructure to take account of the change in direction of gas flows along the pipeline. Integrity surveys ensure that the pipeline remains in a safe operating condition.

**Box 6.6 – Cathodic protection upgrade – Stage 2**

**Cathodic Protection upgrade – Stage 2**

*Background*

Impressed current Cathodic Protection (CP) is used on the AGP to prevent external corrosion. The CP system is one of only two ways the pipeline is protected from corrosion and it is fundamental to the longevity of the pipeline asset. The other protection is the coating which is known to be deteriorating and is the subject of the heat shrink sleeve replacement program (see project at Box 6.9 below).

The spacing of the CP units on the pipeline was originally calculated to allow for expected coating conditions, however there a number of areas where CP of the pipeline has become marginal. This has arisen as a result of the degradation of the pipeline coating and age of the CP system.

A 2004 review of the CP system for the pipeline led to a two stage improvement process being implemented, with stage 1 involving upgrade of two CP sites completed in 2008. A review was conducted in July 2009 which found that a further program of work (stage 2) was required to ensure continued protection.

*Project summary*

Based on a review of the CP protection levels by an external consultant, a number of required improvements were recommended to ensure the pipeline CP system operates adequately in the future. The Cathodic Protection upgrade project – stage 2 includes the following:

- Install new Solar CP unit 1 (KP 529 - Kelly Well)
- Install new Solar CP unit 2 (KP 885 - Ross Creek)
- Install new Solar CP unit 3 (KP 240 - Aileron)
- Convert solar to powered CP site (KP850 – Newcastle Waters)
- Upgrade CP unit (Daly Waters)
- Refurbish Anode bed 1 (Hayfield)
- Refurbish Anode bed 2 (Daly Waters)
- Refurbish Anode bed 3 (KP1506 – Darwin City Gate/Channel Island Spur)
- Telemetry (Townend Rd, Ferguson, Hayfield, Tanumbirini)
- Install new CP unit 1 (Ban Ban Springs)
- Install new CP unit 2 (Wauchope)





- Install new CP unit 3 (Helling)
- SCADA switched interrupters (14)
- Install additional resistance probes (44)
- Install above ground surge diverters (13)
- Install of telemetry at all sites to allow remote monitoring of protection levels, data acquisition and remote operation of interrupters to conduct on/off CP surveys between site visits

*Project costings and timing*

The Cathodic Protection upgrade - stage 2 project costings and timings are shown in Table B6.6 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.6 - Cathodic Protection upgrade stage 2 project costings and timings**

| <b>\$'000 (2009/10)</b>               | <b>2010/11</b> | <b>2011/12</b> | <b>Total</b> |
|---------------------------------------|----------------|----------------|--------------|
| Cathodic Protection upgrade - stage 2 | 1,960          | 1,684          | <b>3,644</b> |

*Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i) and (iii), to ensure the integrity and safety of the pipeline through ongoing compliance with AS2885 (compulsory by operation of the Pipeline Management Plan under the Energy Pipelines Regulations) where NT Gas must comply with AS/NZS 2832.1 which covers:

- Criteria for cathodic protection;
- Measuring techniques and equipment; and
- Operation of cathodic protection systems.

AS/NZS 2832.1 states that where any inspection indicates that satisfactory protection is not fully achieved on the pipeline, timely and appropriate action shall be taken to restore full protection or to instigate other measures that monitor corrosion. This project is intended to ensure full CP of the pipeline.

*Linkages*

Without good CP, corrosion will occur where the pipeline coating is defective. However, even with good CP, if the defective coating is shielding the pipe steel from the CP system, corrosion will continue unabated. This happens with the heat shrink sleeves which are disbonding and shielding.

It should be noted that while considerable CP work is being undertaken in 2010/11 and 2011/12 under the 'special projects' team, ongoing CP work of a more routine nature is also required throughout the access arrangement period. Additional CP replacement works are therefore also included in forecast capital expenditure for the access arrangement period, as discussed further in section 6.3.4 below.



### **Box 6.7 – Hazardous areas assessments and equipment replacement**

#### **Hazardous areas assessment and equipment replacement**

##### *Background*

This project is required to ensure ongoing compliance with the Energy Pipelines Act and the AGP Pipeline Licence to comply with relevant Australian Standards, in particular AS3000, AS2381 and AS2430.

Hazardous areas are places of potential explosion risk due to the possible presence of flammable gas or vapour. The standards require NT Gas to ensure that it identifies all hazardous areas in accordance with the standard, and have in place Hazardous Area Dossiers for all identified sites which identifies and certifies equipment within hazardous areas, and ensures that only equipment rated for specific zones is installed. In addition, the standards require the development of inspection procedures and an inspection program, for personnel trained in hazardous area requirements.

As a result of the hazardous area assessments, NT Gas anticipates that it will need to replace some equipment that does not meet the requirements of the relevant standard to have all equipment within hazardous areas suitably designed and traceable with serial numbers and a history of maintenance. Experience with other pipelines in the broader NT Gas ownership group suggests that most work will be related to rectification at scraper, valve and metering sites. In general, proximity switches, cabling barriers, solenoids and junction boxes are found not to comply. Rectification of these sites is essential to the completion of hazardous area dossiers and training.

##### *Project summary*

This project involves the following:

- The production of hazardous area drawings, that clearly identify the hazardous zones;
- Identification and replacement/rectification of assets identified as not consistent with requirements;
- The production of hazardous area dossiers that identify the equipment that is situated within the hazardous zones and the equipment's certificate of compliance to be in that location;
- Developing hazardous area inspection procedures and an inspection program; and
- Training personnel in hazardous area requirements.

This work is required at various sites along the AGP.

##### *Project costings and timing*

The Hazardous areas assessment and equipment replacement project costings and timings are shown in Table B6.7 below. Expenditure has been forecast using an assumed cost per site based on costs incurred by interstate providers on four sites on the AGP. There remain a further 20 sites on the AGP with electrical equipment operating in hazardous areas. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.7 – Hazardous areas assessment and equipment replacement project costings and timings**

| <b>\$'000 (2009/10)</b>                                      | <b>2010/11</b> | <b>2011/12</b> | <b>Total</b> |
|--|----------------|----------------|--------------|
| Hazardous areas assessment and equipment replacement project | 596            | 368            | 964          |

##### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i) and (iii), as it is required to ensure the safety of sites along the AGP and compliance with current Australian Standards.



#### **Box 6.8 – Palm Valley filtration and slam-shut installation**

##### **Palm Valley filtration and slam-shut installation**

###### *Background*

The change in predominant direction of gas flow on the pipeline and the anticipated cessation of gas supply from the Palm Valley producer in 2011 has meant that gas flows south to Palm Valley and into the Alice Springs Pipeline. This means that gas delivered to Palm Valley may have significant dust content that requires separation before delivery to ensure gas remains within contractual quality specifications prior to metering by others. This is of particular importance when pigging operations are performed as this activity cleans the internal walls of the pipe and generates dust as a result. This must be removed from the gas stream at each scraper station.

The remote operated slam-shut valve is required to enable the pipeline outlet to the Palm Valley to Alice Springs pipeline to be isolated. This may be required to prevent loss of inventory in the case of an emergency and to protect the filters from high differential pressures.

###### *Project summary*

Installation of gas filter and remote operation slam-shut valve at Palm Valley meter station.

###### *Project costings and timing*

The Palm Valley filtration and remote operation slam-shut installation project costings and timings are shown in Table B6.8 below. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.8 – Palm Valley filtration and slam-shut installation project costings and timings**

| <b>\$'000 (2009/10)</b>                                   | <b>2010/11</b> | <b>2011/12</b> | <b>Total</b> |
|---|----------------|----------------|--------------|
| Palm Valley filtration and slam-shut installation project | 160            | 107            | <b>268</b>   |

###### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i) and (ii), as it is required to ensure the integrity of the pipeline and maintain and improve the safety of services provided by means of the pipeline.

#### **Box 6.9 – Heat shrink sleeve replacement project**

##### **Heat shrink sleeve replacement program**

###### *Background*

The field joint coating across the butt weld areas of the pipeline have failed significantly, in many cases causing shielding of the pipe metal from the CP system. The result is corrosion in the vicinity of the field joints that occur at least every 18 meters.

IONIK Consulting were contracted to provide recommendations for an ongoing repair program (IONIK report provided in supporting documents to this submission). IONIK reviewed results from two Rosen ILI surveys, (one conducted in 1997 and the other in 2008) historical CP protection levels and coating survey results. The APA Group integrity team also reviewed results from previous integrity surveys and the IONIK report. The team largely confirmed the report recommendations.

The IONIK report presented the results of two separate growth rate estimations. Proportional and comparison. The proportional growth method was deemed to be not representative of the issue as it assumes complete sleeve degradation from day 1. The comparison growth method indicates more than 1100 defect would require repair within the first 10 years. NT Gas has committed to completing 100 repairs at the heat shrink sleeves per year and to the gathering of valuable additional assessment



information that will allow a more accurate failure prediction.

*Project summary*

At welded joints that have defective heat shrink sleeves indicated by metal loss (as detected in the intelligent Pigging report) excavate, document local conditions, assess the extent of the metal loss and recoat pipeline.

*Program costings and timing*

The heat shrink sleeve replacement program costings for 2010/11 are shown in Table B6.9 below. This program continues at the same level of expenditure in each year of the access arrangement period as part of routine replacement expenditure. Costings have been derived from historical costs of work completed to date. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.9 – Heat shrink sleeve replacement program costings and timings**

| <b>\$'000 (2009/10)</b>                | <b>2010/11</b> |
|--|----------------|
| Heat shrink sleeve replacement program | 503            |

*Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i)-(iii), to ensure the ongoing integrity and safety of the pipeline and to comply with existing regulatory obligations. Section 3.3 of AS2885:3 states:

The continued structural integrity of pipelines relies on elements of pipeline design, construction and operation and maintenance. Procedures shall be developed to ensure structural integrity of the pipeline infrastructure including compressor and pump stations, regulator stations, and metering facilities are retained during operation and maintenance activities. The procedures shall be approved. The operating authority shall address structural integrity issues of at least the following:

- (i) Protective coatings.
- (ii) Pipeline wall thickness.
- (iii) Valves, pig traps, launcher enclosures.
- (iv) Pipe supports.
- (v) Cathodic protection systems/inhibition/corrosion control systems.
- (vi) Pressure control and protective equipment.
- (vii) Stations.
- (viii) Casings.
- (ix) Structures.
- (x) Joints.

This project relates to the (i) (ii) and (x) of the above list.

Section 5.5 of the same standard requires that appropriate remedial action be taken where external corrosion is identified that will compromise the integrity of the pipework before the next inspection.



### **Box 6.10 – Below ground station pipework recoating**

#### **Below ground station pipework recoating**

##### *Background*

During construction of the AGP, complex joints, valves and fittings were coated with coal tar enamel. The majority of stations on the pipeline have detectable coating defects identified during DCVG surveys, CP surveys and physical assessment. During an earlier project, spot samples of the coating within the scraper stations were conducted that confirmed the coating defects exist in the coal tar enamel sections and at the heat shrink sleeves within the stations.

Where corrosion defects exist in buried pipe-work with the heat shrink sleeves and with coal tar, there is high potential for the development of shielding of the pipe steel from the CP system resulting in corrosion. None of this pipe work is able to be inspected through metal-loss pigging, and it is therefore necessary to excavate, inspect and repair each facility.

##### *Project summary*

This program involves removing and recoating the coal tar enamel coating which was used at the end of the line pipe sections and on buried valves, fittings and station pipe welded joints. This would involve excavation, removal of concrete anchors where necessary, blasting, recoating, reinstatement of anchors and backfilling for 37 stations along the pipeline where coal tar was used. It is proposed to replace all of the coating with a modern epoxy.

There are no other options available but to replace the defective coating with coatings that have been proven to have better integrity.

##### *Program costings and timing*

The Below ground station pipework recoating program costings and timings are shown in Table B6.10 below. Costings are based on the costs of doing similar work on other pipelines in Australia. Further information is included in the Asset Management Plan at Attachment C of this submission.

**Table B6.10 – Below ground station pipeline recoating program costings and timings**

| <b>\$'000 (2009/10)</b>                 | <b>2010/11</b> | <b>2011/12</b> | <b>Total</b> |
|---|----------------|----------------|--------------|
| Below ground station pipework recoating | 2,888          | 1,934          | <b>4,822</b> |

##### *Justification under National Gas Rules*

This capital project is relevant to Rule 79(2)(c)(i)-(iii) to ensure the ongoing integrity and safety of the pipeline and to comply with existing regulatory obligations. Section 5.5 of AS2885:3 states:

Assessment of the coating condition on below-ground pipework shall be achieved by evaluation of some or all of the following:

- (a) Cathodic protection data.
- (b) Special coating defect surveys (eg. Pearson or DC-pulsed method surveys).
- (c) Visual inspection at selected locations in bellhole excavations and where the pipeline is exposed for other reasons.

The coating and/or the cathodic protection system shall be maintained to a standard such that—

- (i) the cathodic protection system effectively maintains protection at all coating defects; and
- (ii) coating disbondment is minimized.



NT Gas considers that this special program of works is essential to ensuring the ongoing integrity of the pipeline, particularly in response to known issues discovered through recent integrity surveys of the pipeline. While these projects were not forecast in 2001 as part of the capital program for the earlier access arrangement period, the need for these projects is well supported by internal and external reports and reviews of the current condition of the pipeline – information not known at the time of approval of the earlier access arrangement.

All of the projects included in this program are demonstratively required for pipeline integrity and therefore satisfy the requirements under Rule 79(2)(c)(ii) and (iii) for conforming capital expenditure. Many projects, such as the heat shrink sleeve replacement program and hazardous area assessment and equipment replacement are also essential to maintain the safety of the pipeline, and therefore satisfy the requirements under Rules 79(2)(c)(i). The projects are also consistent with expenditure that would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services, as required under Rule 79(1).

Where credible alternatives exist, NT Gas considered project options and chosen options with the lowest lifecycle costs while still meeting project needs.

These projects are necessary and prudent to ensure ongoing integrity of the pipeline in compliance with NT Gas' pipeline licence obligations to carry out operations in relation to the pipeline in accordance with good pipeline practice using the most appropriate available technologies, and to comply with AS2885, as required under the approved Pipeline Management Plan.

In addition, the delivery of these projects through a special dedicated project team ensures capital sufficiency and deliverability, and that the projects are delivered at the lowest sustainable cost.

The main driver of these projects is to correct integrity issues, however in the past NT Gas would have had significant difficulty assembling a project team to deliver such an enhanced program of works. In recent times, NT Gas has been able to schedule this program to take advantage of some limited availability of engineering and contracting labour due to the slight downturn in demand for labour resources resulting from the global financial crisis. Not only does NT Gas consider that the special projects structure will lead to significant labour cost savings (which may not be available in the future), the structure also allows NT Gas to deliver the individual projects through specific project delivery arrangements allowing scheduling efficiencies to be realised throughout the program of works. It is therefore doubtful that this program could be delivered at another time or at a similar cost, or that the program could be successfully spread over a number of years while still accessing the synergies available from a dedicated project management and delivery team.

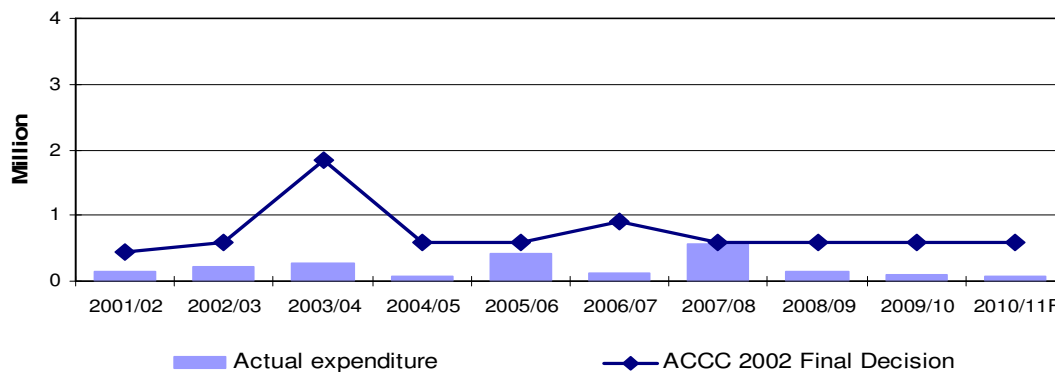
NT Gas therefore considers this program of works to satisfy the requirements for conforming capital expenditure under Rule 79 and should be approved by the AER for inclusion in the capital base.



### 6.2.3 Non-system capital expenditure

Non-system capital expenditure over the earlier access arrangement period compared to the annual amounts approved by the ACCC are shown in Figure 6.3 below and in Table 6.2 at the end of this chapter.

**Figure 6.3 – Non-system capital expenditure comparison to forecast over the earlier access arrangement period**



As can be seen from Figure 6.3 above, non-system capital expenditure was significantly below forecast. This was primarily due to two main factors:

- a delay in the scheduled communication system upgrade (forecast for 2003/04 but incurred in 2005/06-2007/08). The delay subsequently allowed NT Gas to take advantage of a change in available technologies and utilise satellite communications at a significant saving; and
- the prudent deferral of the replacement of two emergency response trucks (forecast for 2007 at \$309,000 (\$2009/10), extending the operating life of these trucks into the next access arrangement period, as inspection of the trucks at the time of forecast replacement found them to be in good condition and replacement at that stage unnecessary.<sup>55</sup>

Offsetting these savings was unforecast expenditure in 2007/08 related to the replacement of finance software at a cost of \$243,000 (\$2009/10). The purchase of new finance software was necessary following the transfer of majority ownership of NT Gas from Alinta to APA Group. NT Gas had formerly been using Alinta's SAP finance system, and was required to purchase a new finance system (Finance One), as it could no longer use the Alinta system following the sale.

NT Gas considers that its non-system capital expenditure over the access arrangement period satisfies the requirements of Rule 79 and should be rolled into

<sup>55</sup> These trucks were included on NT Gas' asset register at the expiry of earlier leasing arrangements. While this expenditure was part of forecast capital expenditure in the earlier access arrangement, NT Gas' usual practice is to lease these types of assets. Provision for replacement of existing emergency response trucks under a new lease is included as a 'step change' to forecast operating expenditure in the access arrangement period.





the opening capital base for the period. All projects were developed through the planning processes described in Chapter 4 above on a needs basis, and were subject to rigorous review by PWC under existing contractual arrangements.

In addition, all significant projects undertaken were approved by the ACCC in 2002 for inclusion in the capital base as forecast conforming capital expenditure, with the exception of the finance system upgrade, which was not forecast (as it related to an unanticipated sale of assets), but necessary as NT Gas could not operate without a finance system in place.

#### 6.2.4 Capital expenditure by asset class

NT Gas' actual and estimated capital expenditure by asset class over the earlier access arrangement period is shown in Table 6.3 at the end of this chapter.

NT Gas has revised its asset classes for the access arrangement period by splitting *Building* out of the *Operation and Management facilities* asset class. NT Gas has created a new category for Building to better reflect the economic life of assets in this asset class which range from IT equipment and building fit out expenditure (for example computers, chairs and desks) which have a relatively short economic life, and buildings which have a longer economic life.

Both historic and forecast capital expenditure included in this submission is provided in the revised asset classes to assist in the identification of historic and forecast trends in expenditure. Table 6.1 below sets out the revised asset classes and inclusions in each class.

**Table 6.1 – Asset classes**

| Asset class                         | Description   |
|-------------------------------------|---|
| Pipeline                            | Pipeline works and associated pipeline assets such as cathodic protection units, water bath heaters, solar facilities, CP batteries (that is, integrity purposes) |
| Compression                         | Rotating equipment  |
| Meter stations                      | Facilities at delivery points including regulation, filtration, measurement, gas quality and heating assets   |
| SCADA and Communications            | Facilities for remote data collection, transmission and control   |
| Operation and Management facilities | Low value assets, computers, furniture, tools and equipment, mobile plant, vehicles   |
| Building                            | Buildings and land  |

NT Gas does not use these asset categories for accounting purposes and therefore some judgement has been applied in allocating both historic and forecast expenditure into these categories. To the extent possible, NT Gas has applied the same allocation principles as adopted in the previous access arrangement to ensure consistency between historic and forecast expenditure.





**Table 6.2 – Comparison of ACCC 2002 Final Decision and outturn capital expenditure over the earlier access arrangement period**

| \$ '000 (2009/10)   | 2001/02      | 2002/03        | 2003/04      | 2004/05      | 2005/06      | 2006/07        | 2007/08    | 2008/09    | 2009/10    | 2010/11F      | Total         |
|---|--------------|----------------|--------------|--------------|--------------|----------------|------------|------------|------------|---------------|---------------|
| <b>ACCC 2002 Final Decision</b>   |              |                |              |              |              |                |            |            |            |               |               |
| Expansion capital   | 0            | 0              | 0            | 0            | 0            | 0              | 0          | 0          | 0          | 0             | 0             |
| Replacement capital   | 29           | 3,057          | 83           | 0            | 82           | 2,608          | 81         | 0          | 81         | 0             | 6,021         |
| Non system capital  | 453          | 598            | 1,847        | 599          | 590          | 901            | 581        | 587        | 584        | 599           | 7,339         |
| <b>Total forecast</b>   | <b>481</b>   | <b>3,655</b>   | <b>1,931</b> | <b>599</b>   | <b>672</b>   | <b>3,509</b>   | <b>662</b> | <b>587</b> | <b>665</b> | <b>599</b>    | <b>13,360</b> |
| <b>Actual and forecast capital expenditure</b>  |              |                |              |              |              |                |            |            |            |               |               |
| Expansion capital   | 0            | 0              | 0            | 0            | 0            | 0              | 0          | 0          | 361        | 7,032         | 7,392         |
| Replacement capital   | 124          | 250            | 3,198        | 362          | 124          | 218            | 163        | 442        | 218        | 12,128        | 17,226        |
| Non system capital  | 144          | 209            | 268          | 82           | 429          | 129            | 572        | 159        | 91         | 82            | 2,165         |
| <b>Total actual</b>   | <b>268</b>   | <b>459</b>     | <b>3,466</b> | <b>444</b>   | <b>553</b>   | <b>347</b>     | <b>734</b> | <b>601</b> | <b>670</b> | <b>19,242</b> | <b>26,783</b> |
| <b>Variance between ACCC 2002 Final Decision and NT Gas actual and forecast capital expenditure</b> |              |                |              |              |              |                |            |            |            |               |               |
| Expansion capital   | 0            | 0              | 0            | 0            | 0            | 0              | 0          | 0          | 361        | 7,032         | 7,392         |
| Replacement capital   | 95           | (2,808)        | 3,115        | 362          | 42           | (2,390)        | 82         | 442        | 137        | 12,128        | 11,205        |
| Non system capital  | (308)        | (389)          | (1,580)      | (516)        | (161)        | (772)          | (10)       | (428)      | (493)      | (516)         | (5,174)       |
| <b>Total variance</b>   | <b>(213)</b> | <b>(3,197)</b> | <b>1,536</b> | <b>(155)</b> | <b>(119)</b> | <b>(3,162)</b> | <b>72</b>  | <b>14</b>  | <b>5</b>   | <b>18,643</b> | <b>13,424</b> |

Values in parentheses represent negative numbers, in this case an underspend in that year.



**Table 6.3 – Capital expenditure by asset class over the earlier access arrangement period**

| \$ '000 (2009/10)                 | 2001/02    | 2002/03    | 2003/04      | 2004/05    | 2005/06    | 2006/07    | 2007/08    | 2008/09    | 2009/10    | 2010/11F      | Total         |
|-----------------------------------|------------|------------|--------------|------------|------------|------------|------------|------------|------------|---------------|---------------|
| Pipeline                          | 21         | 31         | 0            | 0          | 0          | 146        | 0          | 254        | 361        | 8,969         | 9,782         |
| Compression                       | 0          | 0          | 0            | 0          | 0          | 0          | 0          | 0          | 0          | 0             | 0             |
| Meter Stations                    | 0          | 160        | 494          | 119        | 0          | 0          | 0          | 4          | 113        | 9,864         | 10,754        |
| SCADA & Communications            | 2          | 2          | 2,851        | 87         | 259        | 58         | 4          | 102        | 13         | 0             | 3,376         |
| Operation & Management facilities | 245        | 267        | 121          | 238        | 294        | 143        | 731        | 240        | 183        | 409           | 2,871         |
| Building                          | 0          | 0          | 0            | 0          | 0          | 0          | 0          | 0          | 0          | 0             | 0             |
| <b>Total</b>                      | <b>268</b> | <b>459</b> | <b>3,466</b> | <b>444</b> | <b>553</b> | <b>347</b> | <b>734</b> | <b>601</b> | <b>670</b> | <b>19,242</b> | <b>26,783</b> |



## 6.3 Forecast capital expenditure

### 6.3.1 Overview and forecast methodology

Forecast capital expenditure over the access arrangement period is shown in Table 6.4 below. These forecasts have been derived through the application of planning processes and asset management principles discussed in chapter 4 above, and comply with the requirements of Rule 79 for conforming capital expenditure, as discussed in relation to capital expenditure for each driver.

**Table 6.4 – Forecast capital expenditure over the access arrangement period**

| \$ '000 (2009/10) | 2011/12      | 2012/13      | 2013/14      | 2014/15      | 2015/16      | Total         |
|-------------------|--------------|--------------|--------------|--------------|--------------|---------------|
| Expansion         | 0            | 0            | 0            | 0            | 0            | 0             |
| Replacement       | 8,400        | 1,366        | 1,097        | 1,078        | 1,071        | 13,012        |
| Non-system        | 106          | 106          | 412          | 107          | 314          | 1,046         |
| <b>Total</b>      | <b>8,506</b> | <b>1,473</b> | <b>1,509</b> | <b>1,185</b> | <b>1,385</b> | <b>14,058</b> |

NT Gas' forecast capital expenditure is expected to decline in the access arrangement period in 2012/13 after completion of the immediate integrity program discussed in section 6.2.2 above. Capital expenditure over the period, however is expected to be higher than the earlier period due to the need to continue enhanced integrity works on the pipeline, in particular in relation to the replacement of heat shrink sleeves, which was not a feature of expenditure in the earlier period as these defects were not previously detected.

Actual capital expenditure over the earlier access arrangement period and forecast capital expenditure are shown in Figure 6.4 below.



**Figure 6.4 – Capital expenditure trend over the earlier access arrangement period and access arrangement period**

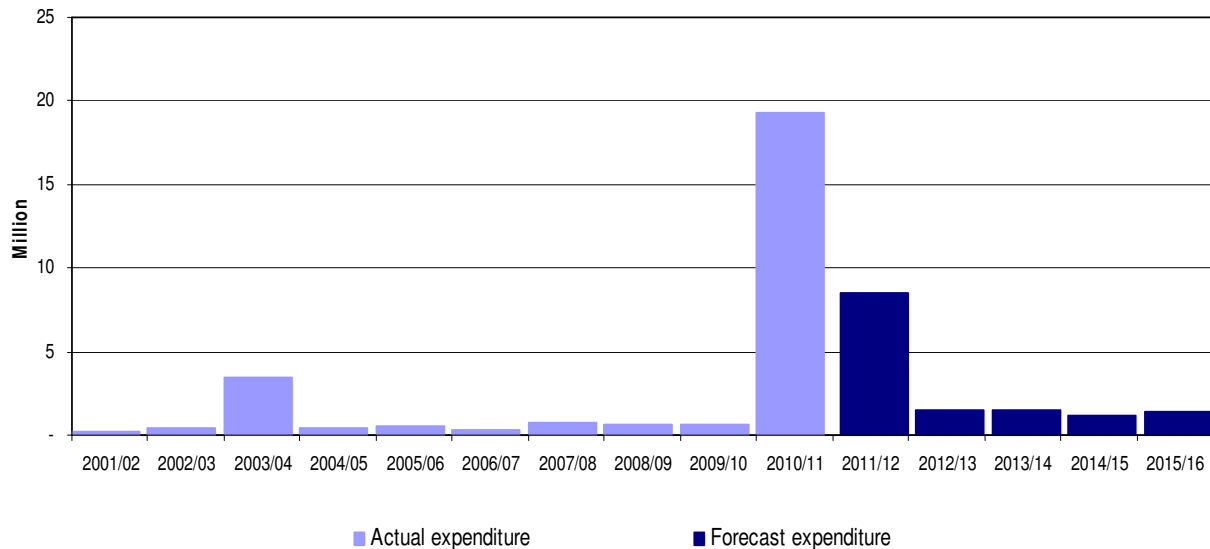
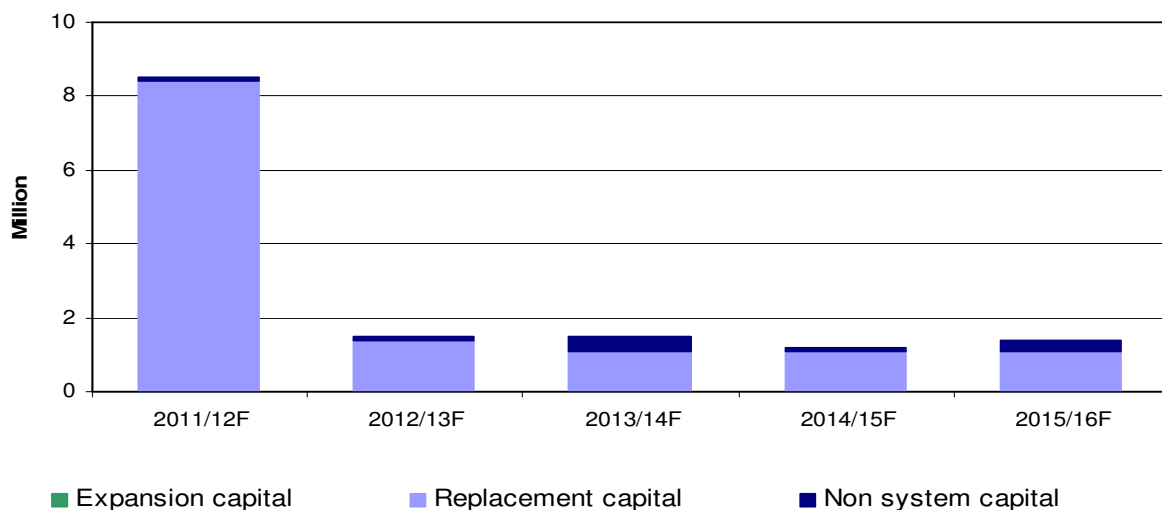


Figure 6.5 shows forecast capital expenditure by driver over the access arrangement period.

**Figure 6.5 – Forecast capital expenditure over the access arrangement period**



NT Gas considers that its forecast capital expenditure for the access arrangement period satisfies the requirements under Rule 79 that it be expenditure that would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services, as required under Rule 79(1).

Forecast capital expenditure is not expected to be funded by parties other than NT Gas.



### *Forecast methodology*

Capital expenditure for the access arrangement period has been forecast using a zero-base approach, derived from known capital expenditure programs, the most significant of which set are out in the Asset Management Plan. All projects with forecast expenditure above \$200,000 are described below, with some projects at a lesser value described where they make a significant contribution to the forecast.

Outsourced labour components in forecast capital projects are escalated as appropriate by NT Gas' labour escalator discussed further below.

There are no contingency allowances included in capital expenditure numbers. NT Gas notes that there is a material risk that some estimates will be too low owing to uncertainties in forecasting costs accurately, particularly in the later years of the access arrangement period. The unique operating environment in NT also adds uncertainty in cost forecasting due to variable climatic conditions particularly in the wet season that can impact the scheduling of work, and the vast distances involved in transporting goods and labour to remote sites.

This cost risk means that there is a skewed likelihood towards costs being materially higher than forecast compared to the likelihood that costs will be lower. Despite these risks, NT Gas considers that its forecast for capital expenditure is the best possible in the circumstances, and is consistent with the Rule 79 requirements for conforming capital expenditure. NT Gas considers that any required reductions to this forecast would place it at material risk of not recovering its efficient costs in providing reference services, which would be contrary to the NGL revenue and pricing principles.<sup>56</sup>

### 6.3.2 Escalation

Outsourced labour in base estimates of capital expenditure for the period have been escalated using a labour cost escalator derived from average weekly earnings for the electricity, gas, water and waste water services over the past five years as reported by the Australian Bureau of Statistics (ABS), and economic outlook information for the Northern Territory.

The labour escalator has been derived from the ABS national average weekly earnings data for electricity, gas, water and waste water services.<sup>57</sup> The average annual growth in this labour index over the last five years was 4.47 per cent (nominal). Using this value as a base, NT Gas has applied a 4 per cent nominal or 1.5 per cent real labour cost escalator to the outsourced labour component of forecast capital expenditure.

NT Gas considers that this forecast escalator is reasonable as it is lower than salary growth experienced by NT Gas over the same period of 4.34 per cent. The key

---

<sup>56</sup> National Gas Law, section 24

<sup>57</sup> Australian Bureau of Statistics, Catalogue 6302.0 – Series ID A2719021L (Earnings; Persons; Total earnings; Electricity, Gas, Water and Waste Services), series end February 2010



elements contributing to NT Gas labour costs in the earlier access arrangement period are expected to remain in place over the access arrangement period including:

- Scarcity of skilled labour resources;
- Competition with the mining and utility sectors for labour resources; and
- Relatively high turnover rates contributing to higher average salaries (from more frequent re-negotiation and resetting of terms of employment in line with prevailing conditions).

NT Gas also takes account of a forecast easing in population and employment growth in NT in the coming five years, as reported by Access Economics in its September quarter 2010 economic brief for the NT Government, by adopting a value below the previous five year average for the index.<sup>58</sup>

A split of forecast input costs for capital expenditure (separating outsourced labour components from others) has been developed and applied based on analysis of the labour/other cost split in a sample of projects. Internal labour costs have not been included in capital expenditure forecasts and have been separately escalated – see forecast operating expenditure at section 9.3.

### 6.3.3 Expansion capital expenditure

In general, demand forecasts, in particular for peak demand (capacity and utilisation), are relevant to expansion capital expenditure. As described in chapter 5 in relation to demand and utilisation forecasts, NT Gas does not anticipate demand to exceed the current capacity of the pipeline during the access arrangement period. As a result, NT Gas does not forecast any expansion conforming capital expenditure in the access arrangement period.

### 6.3.4 Replacement capital expenditure

Forecast replacement expenditure in 2011/12 includes a component of the integrity works program project expenditure discussed above in 6.2.2. This includes year two expenditure associated with the following projects:

- Installation of filtration and slamshut at Palm Valley;
- Channel Island Spurline piggability;
- Hazardous area assessment and equipment replacement;
- Southbound piggability project;
- Heat shrink sleeve replacement;

---

<sup>58</sup> Access Economics 2010, Economic Brief, September quarter 2010.



- Cathodic Protection upgrade – stage 2; and
- Below ground station pipeline recoating.

Details of forecast expenditure and justifications for these projects can be found above in the project boxes in section 6.2.2 and so are not repeated here. This information, however, is relevant to support these components of forecast capital expenditure in the access arrangement period and should be referred to as part of the information relevant to forecast capital expenditure.

The enhanced integrity program makes up \$ 7.4 million of total expenditure \$8.4 million in 2011/12. The remaining 'routine' expenditure in 2011/12 and later years of the period is largely associated with two ongoing integrity projects - replacement of cathodic protection sites and heat shrink sleeve replacement.

The replacement of cathodic protection sites along the length of the pipeline includes:

- Four additional solar powered CP sites;
- Two additional conventional powered CP sites;
- Replacement of five CP ground bed sites;
- Replacement of exhausted anodes; and
- Replacement of battery chargers at 240v sites.

This work is required to ensure the effectiveness of CP, and is therefore essential for ongoing integrity of the pipeline. As the pipeline ages and its coating further degrades, there is a need for additional CP sites to ensure adequate coverage. In addition, existing sites must be periodically replaced as they wear out and the protection they provide becomes less effective.

The need for these replacement works were identified in a survey of the CP system conducted in 2009, which identified areas of the pipeline not covered by existing CP. This expenditure therefore makes up a proportion of the observed increase in 'routine' replacement capital expenditure in the access arrangement period compared with the earlier access arrangement period.

This category also includes ongoing expenditure in the replacement of heat shrink sleeves in each year of the period.

SCADA and communications expenditure includes upgrades in the SCADA system software to retain currency and effectiveness of SCADA, as well as an expected change in satellite providers.

Meter station expenditure largely involves replacement of demountable huts at two meter station sites during the period, as part of the rolling replacement program of huts. The demountable huts are in poor condition due to the harsh climatic conditions they endure and require replacement to ensure integrity of electrical and SCADA



equipment housed in the huts which would come under threat if the huts are not replaced.

NT Gas has also included an allowance for other general capital expenditure, usually associated with the replacement or acquisition of tools and minor equipment as required because of age, loss or breakage, or because of new requirements (where existing tools not fit for purpose or safe for use). The allowance for this item has been estimated based on historical average expenditure of this kind, and allocated to the appropriate asset classes using the historical profile of expenditure.<sup>59</sup> Because of its nature, it is difficult to specify in advance where this expenditure will be made, however, expenditure of this kind is essential for the operation and maintenance of the pipeline and therefore should be considered efficient and prudent, consistent with the requirements of Rule 79.

NT Gas considers that its forecast replacement capital expenditure is prudent and efficient as it is required for the ongoing maintenance of the pipeline in line with accepted good industry practice and requirements under existing standards (for example maintaining CP works). The proposed expenditure is relatively stable over the period, reflecting its largely routine nature.

### 6.3.5 Non-system capital expenditure

Forecast non-system capital expenditure is shown in Table 6.4 above.

The non-system capital expenditure forecast has been derived by reference to expenditure in this category in the earlier access arrangement period as follows:

- Expenditure in the earlier access arrangement period was divided into annual routine and non-annual elements;
  - Non-annual elements include voice and data communications upgrades undertaken during the earlier period;
- Average annual routine expenditure over the earlier period was calculated and this value formed the basis of forecast expenditure;
- Expected non-annual expenditure was then added to the forecast in the year in which that expenditure is expected to be incurred.

Non-annual elements added to the forecast included expected upgrades of data and voice communications in 2013/14 and 2015/16.

NT Gas considers that its forecast non-system capital expenditure is consistent with expenditure that would be undertaken by a prudent service provider acting efficiently, in accordance with Rule 79(1). The forecast expenditure on assets such as office equipment and computers is required to ensure the continued operation of the pipeline under Rule 79(2)(c) to maintain and improve the safety and integrity of

---

<sup>59</sup> The majority of this expenditure is associated with the operation and management facilities asset class.





services and ensure ongoing compliance with regulatory obligations. This expenditure is spread across all NT Gas sites.

### 6.3.6 Forecast capital expenditure by asset class

As discussed above in relation to historic capital expenditure, NT Gas has revised its asset classes in the access arrangement period by splitting *Building* from the *Operating and Management facilities* asset class. For consistency, NT Gas has presented both historic and forecast capital expenditure using the revised asset classes, as shown in Table 6.5 below.

For revenue purposes, the split in the Operating and Management facilities category has only been applied in relation to forecast capital expenditure in the access arrangement period.

**Table 6.5 – Forecast capital expenditure by asset class**

| \$ '000 (2009/10)                 | 2011/12      | 2012/13      | 2013/14      | 2014/15      | 2015/16      | Total         |
|-----------------------------------|--------------|--------------|--------------|--------------|--------------|---------------|
| Pipeline                          | 7,662        | 911          | 920          | 817          | 883          | 11,193        |
| Compression                       | 0            | 0            | 0            | 0            | 0            | 0             |
| Meter Stations                    | 588          | 115          | 13           | 113          | 14           | 842           |
| SCADA & Communications            | 136          | 319          | 450          | 136          | 356          | 1,398         |
| Operation & Management facilities | 119          | 127          | 125          | 119          | 130          | 620           |
| Building                          | 1            | 1            | 1            | 1            | 1            | 5             |
| <b>Total</b>                      | <b>8,506</b> | <b>1,473</b> | <b>1,509</b> | <b>1,185</b> | <b>1,385</b> | <b>14,058</b> |

### 6.3.7 Outsourced forecast capital expenditure

The AER RIN<sup>60</sup> requires NT Gas to submit certain information related to outsourced forecast capital expenditure that contributes in a material way to the provision of pipeline services. NT Gas has no contracts in place for forecast capital expenditure. There are, however, some ongoing relationships with external providers that NT Gas expects will continue in the access arrangement period. Details of these relationships are provided in confidential Attachment F.

NT Gas has considered and reported all outsourced arrangements and therefore the materiality threshold it has applied for this purpose is zero.

<sup>60</sup> AER RIN clause 2.5.6



## **7 Capital base**

### **7.1 Opening capital base for the access arrangement period**

#### **7.1.1 Opening capital base for the earlier access arrangement period**

The earlier access arrangement was the first access arrangement for the AGP and established the initial capital base (ICB). The ICB was set for 1 July 2001 at \$228.5 million (\$nominal) on the basis of an Optimised Deprival valuation. This value did not reflect an estimate of capital expenditure in 2000/01 that requires adjustment, as would be the case if the earlier access arrangement period followed from a previous access arrangement.

NT Gas has therefore rolled forward its capital base over the earlier access arrangement period from a starting value of \$228.5 million (\$nominal) without adjustment.

#### **7.1.2 Conforming capital expenditure during earlier access arrangement period**

Conforming capital expenditure for the earlier access arrangement period is described in section 6.2 and is submitted in Table 6.2. As discussed in chapter 6, NT Gas considers its capital expenditure in the earlier access arrangement period to be prudent and efficient. Significant expenditure in 2010/11 was required to address integrity issues that had emerged on the pipeline during the earlier access arrangement period, and this expenditure has resulted in an overspend of \$13.4 million. This overspend was offset in part by savings achieved in the early part of the period by:

- not undertaking the Mereenie looping project due to changes in flow conditions on the pipeline not anticipated at the time of approval of the earlier access arrangement;
- achieved efficiencies in the communication upgrade project by moving to satellite communications; and
- prudent deferral of the replacement of two emergency response trucks which were found, after inspection and risk assessment, to be suitable for continued use.



### 7.1.3 Amounts to be added to the capital base under rules 82, 84 and 86

Rule 82 addresses the treatment of capital contributions by users in capital expenditure. The effect of the rule is that capital expenditure, to the extent contributed by users, is not eligible for inclusion in the capital base unless a mechanism is proposed under sub-rule 82(3) to prevent the service provider from raising increased revenue as a result of the inclusion.

NT Gas has included in its access arrangement at clause 3.2 a mechanism to ensure that it does not receive any benefit through increased Revenue from any User's contribution to the Capital Base.

Under the mechanism, capital contributions are treated as revenue in the year in which they are received. The forecast amount of capital contributions is then deducted from the total revenue requirement in determining the revenue requirement to be recovered through tariffs. Through this process, NT Gas returns to customers, by way of lower tariffs, the full benefit associated with the return on and return of contributed capital. The up-front reduction in tariff revenue exactly equals, in present value terms, the return on and return of capital over the life of the capital investment.

NT Gas did not receive any capital contributions in respect of non-conforming capital expenditure in the period, and therefore there are no amounts to be added to the opening capital base under Rule 82.

Rule 84 relates to the formation of a speculative capital expenditure account, and how amounts included in a speculative capital expenditure account can be added to the capital base. NT Gas does not currently have any expenditure in a speculative capital expenditure account, and did not roll any expenditure from a speculative capital expenditure account into the capital base during the earlier access arrangement period.

Further, NT Gas did not undertake any non-conforming capital expenditure over the earlier access arrangement period that was recovered through a surcharge or that was added to a speculative capital expenditure account.

A redundant asset is an asset that ceases to contribute in any way to the delivery of pipeline services. NT Gas has not identified any assets that became redundant during the earlier access arrangement period. NT Gas has not identified any redundant assets in the earlier access arrangement period that must be removed from the capital base.

Rule 86 relates to the re-use of redundant assets. NT Gas did not re-use any assets during the earlier access arrangement period that it had previously identified as redundant, and therefore does not forecast any amounts to be added to the capital base under this Rule.



#### 7.1.4 Disposals

NT Gas had minor disposals in the earlier access arrangement period which are recorded in the Post Tax Revenue Model (PTRM). Disposals are netted off capital additions recorded in Table 7.10.

#### 7.1.5 Assets subject to insurance or other compensation claims

The AER RIN requires NT Gas to identify any assets that make up part of the opening capital base that have been subject to compensation claims through legal or court action, insurance or other processes in the earlier access arrangement period.

NT Gas confirms that no assets comprising the opening capital base have been subject to such claims.

#### 7.1.6 Depreciation over the earlier access arrangement period

The ACCC's 2002 Final Decision concluded that the appropriate residual value of the ABDP was \$61.84 million:

Proposed Amendment A2.4

In order for NT Gas' access arrangement for the ABDP to be approved, the depreciation schedule must be based on straight line accelerated depreciation of the Commission's initial capital base of \$176.2m at 1 July 2001 to a residual value of \$61.84m at 1 July 2011.<sup>61</sup>

As discussed extensively in the 2002 Final Decision, the depreciation schedule was driven primarily by the need to achieve this residual value for the leased pipeline assets.

However, consistent with the ACCC's nominal revenue requirement approach at the time, the amounts for regulatory depreciation in the ACCC's 2002 Final Decision were a blend of depreciation of the capital base (return on capital) and indexation. Table 3.2 of the 2002 Final Decision showed the composite depreciation and indexation figure.

In order to roll forward the capital base, it is necessary to disaggregate the depreciation and indexation components from the depreciation schedule in the ACCC 2002 Final Decision.

To accomplish this, NT Gas has calculated the amount of indexation included the 2002 ACCC Final Decision (based on the ACCC's assumed 2.19 per cent CPI forecast), and added this back to the published depreciation figures to derive the amount of depreciation before the indexation adjustment. The result of this calculation is shown in Table 7.6 at the end of this chapter.

---

<sup>61</sup> ACCC 2002, *Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline: Final Decision*, 4 December, p 61



This depreciation component has been applied in the asset base roll forward model and the capital base indexed according to outturn CPI changes.

### 7.1.7 Indexation of the capital base

As discussed above, the ACCC 2002 Final Decision included a forecast CPI increase of 2.19 per cent per annum.<sup>62</sup> NT Gas has rolled forward the capital base using actual outturn CPI applicable to the relevant years, as shown in Table 7.7. This indexation component has been applied in the asset base roll forward model, as shown in Table 7.8. Both of these tables are provided at the end of this chapter.

## 7.2 Projected capital base for the access arrangement period

### 7.2.1 Opening capital base in 2011

Consistent with the provisions of Rule 77(2), the opening capital base as at 1 July 2011 is the same as the closing capital base as at 30 June 2011, which is calculated in Table 7.10 at the end of this chapter.

### 7.2.2 Forecast capital expenditure

Forecast capital expenditure is addressed in section 6.3. In summary, forecast capital expenditure is shown in Table 7.1 below.

**Table 7.1 – Forecast capital expenditure**

| \$'000 (2009/10)                   | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|------------------------------------|---------|---------|---------|---------|---------|
| Total forecast capital expenditure | 8,506   | 1,473   | 1,509   | 1,185   | 1,385   |

### 7.2.3 Non-conforming capital expenditure

#### *Capital contributions*

NT Gas does not forecast any non-conforming capital expenditure to be recovered through a capital contribution during the access arrangement period.

#### *Surcharges and speculative capital expenditure account*

NT Gas does not forecast any non-conforming capital expenditure to be recovered through a surcharge during the access arrangement period.

---

<sup>62</sup> ACCC 2002, *Final Decision*, p 80



NT Gas does not currently have any expenditure in a speculative capital expenditure account, and does not forecast any expenditure during the access arrangement period that it intends to add to speculative capital expenditure account.

### *Disposals*

Disposals in the earlier access arrangement period were minor – totalling less than \$30,000 (\$nominal) over the 10 year period. NT Gas does not forecast any disposals in the access arrangement period.

## 7.2.4 Depreciation over the access arrangement period

While the earlier access arrangement indicated an overall economic life of pipeline assets of 65 years, the earlier access arrangement forecast an expected residual value of the pipeline assets and depreciated the pipeline to that residual value over the period ending 30 June 2011. Depreciation over the earlier access arrangement period therefore presented a 'kinked' depreciation curve, as shown in the ACCC's 2002 Final Decision.<sup>63</sup>

Going forward, depreciation is calculated by applying the remaining economic life of the assets over the opening capital base value as at 1 July 2011.

Remaining asset lives reflect the composite remaining economic life of assets in the class, reflecting that new assets will be included in the class at the full economic life, and are shown in Table 7.2 below.

**Table 7.2 – Remaining Economic Lives**

| Asset class  | Economic Life (years) | Average Remaining Economic Life (years) |
|--|-----------------------|---|
| Transmission Pipeline  | 80                    | 58.7                                    |
| Compressor Stations:<br>Rotating Equipment<br>Station Facilities | 30                    | 20.0                                    |
| Regulation and Metering Stations<br>Odourising Stations          | 50                    | 31.0                                    |
| SCADA  | 15                    | 6.4                                     |
| O&M Facilities   | 10                    | 4.0                                     |
| Buildings  | 40                    | 36.0                                    |

The ACCC's 2002 Final Decision included depreciation for the Operations and Maintenance Facilities asset class with a useful life of 65 years. As discussed in section 6.2.4, the assets in this class include computers and other office equipment, tools, and other assets of limited lives. For this access arrangement, NT Gas has

<sup>63</sup> ACCC 2002, *Final Decision*, Figure 3.1



prospectively amended the standard life of this class to 5 years (and the remaining life of the opening asset value to 4 years) to more accurately reflect the limited life of these assets.

To allow for the differences in asset lives, NT Gas has disaggregated the Operations and Maintenance Facilities asset class to provide for a new Buildings asset class with a longer economic life of 40 years.

Applying these remaining lives to assets in service as at 1 July 2011, and the economic asset lives to new capital expenditure, yields the depreciation forecast shown in Table 7.3 below.

**Table 7.3 – Forecast straight line depreciation over the access arrangement period**

| \$ '000 (nominal)                | 2011/12      | 2012/13      | 2013/14      | 2014/15      | 2015/16      |
|----------------------------------|--------------|--------------|--------------|--------------|--------------|
| Transmission Pipeline            |              |              |              |              |              |
| Compressor Stations              |              |              |              |              |              |
| Regulation and Metering Stations |              |              |              |              |              |
| SCADA                            |              |              |              |              |              |
| O&M Facilities                   |              |              |              |              |              |
| Buildings                        |              |              |              |              |              |
| Confidential - redacted          |              |              |              |              |              |
| <b>Total</b>                     | <b>7,369</b> | <b>6,743</b> | <b>6,967</b> | <b>7,205</b> | <b>3,710</b> |

Note: Confidential information redacted

## 7.2.5 Indexation of the capital base

Consistent with the AER's approach embedded in the PTRM, the capital base has been indexed to allow for forecast inflation over the access arrangement period.

As shown in section 8.9, the forecast inflation rate applied to the capital base is 2.5 per cent per year.

The forecast amount of indexation applied to the capital base is shown in Table 7.4 below.

**Table 7.4 – Forecast indexation of the capital base**

| \$'000 (nominal) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|------------------|---------|---------|---------|---------|---------|
| Total            | 2,811   | 2,930   | 2,876   | 2,817   | 2,742   |



## 7.2.6 Projected capital base over the period

The projected capital base for the access arrangement period<sup>64</sup> is shown in Table 7.5 below.

**Table 7.5 – Projected capital base for the access arrangement period**

| \$ '000 (nominal)                            | 2011/12        | 2012/13        | 2013/14        | 2014/15        | 2015/16        |
|--|----------------|----------------|----------------|----------------|----------------|
| Opening capital base                         | 112,433        | 117,192        | 115,032        | 112,678        | 109,688        |
| <i>plus</i> forecast capex                   | 9,317          | 1,653          | 1,737          | 1,398          | 1,674          |
| <i>less</i> forecast regulatory depreciation | 4,558          | 3,814          | 4,091          | 4,388          | 968            |
| <i>less</i> forecast disposals               | -              | -              | -              | -              | -              |
| <i>less</i> forecast redundant assets        | -              | -              | -              | -              | -              |
| <b>Closing capital base</b>                  | <b>117,192</b> | <b>115,032</b> | <b>112,678</b> | <b>109,688</b> | <b>110,394</b> |

## 7.2.7 Tax Asset Base

The Rules do not mandate a particular approach for dealing with taxation in the access arrangement revision process. Rather, Rule 72(1)(h) requires the service provider to indicate the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated.

For the purposes of this access arrangement, NT Gas has adopted a post tax approach. Under this approach, the cash flows of the business include an estimate of the amount of tax payable on regulatory revenues.

In order to calculate the estimated amount of corporate tax payable, it is necessary to establish the amount of tax depreciation that can be deducted from taxable revenue to determine the amount of tax payable. As tax depreciation is based on different depreciation rates than those used for statutory accounting or regulatory purposes, the value of the Tax Asset Base (TAB) is likely to be different at any given point in time than either the statutory or regulatory asset base. It is therefore necessary to establish a TAB for regulatory purposes.

### *Establishing the Tax Asset Base*

With the alignment of regulatory approaches under the AER, several businesses have established a TAB in recent years, including ENERGEX,<sup>65</sup> Ergon Energy,<sup>66</sup> and

<sup>64</sup> As required by Rule 72(1)(c)

<sup>65</sup> AER 2009, *Queensland Draft distribution determination 2010–11 to 2014–15: Draft decision* 25 November; McGrathNicol 2009, *Assessment of Energex's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 23 September





ETSA Utilities.<sup>67</sup> Each of these businesses applied a slightly different approach to establishing the TAB, each of which were accepted by the AER.

In its 2002 Final Decision for the AGP, the ACCC applied a post tax approach, and therefore included a cost of tax in the regulated revenue requirement. This required the ACCC to estimate a TAB in order to calculate the amount of tax depreciation applied to calculate the tax payable amount to be included in the total revenue requirement.

NT Gas has adopted this TAB and rolled it forward using the same principles as the normal asset base rollforward. That is, NT Gas has adopted the opening TAB in the earlier access arrangement period, and rolled it forward using actual capital expenditure. As the TAB is not indexed, it was not necessary to update the rollforward for outturn CPI increases. The TAB rollforward is shown in Table 7.9 at the end of this chapter.

The TAB is then applied to determine the corporate income tax allowance derived from the AER's Post Tax Revenue Model, as indicated in Table 10.3.

---

<sup>66</sup> AER 2009, *Queensland Draft distribution determination 2010–11 to 2014–15: Draft decision*, 25 November; McGrathNicol 2009, *Assessment of Ergon Energy's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 29 September

<sup>67</sup> AER 2009, *South Australia Draft distribution determination 2010–11 to 2014–15 Draft decision*, 25 November; McGrathNicol 2009, *Assessment of ETSA's proposed methodology and calculation of its tax asset base for the 2010–2015 regulatory control period*, 2 October



**Table 7.6 - Disaggregation of ACCC 2002 Final Decision forecast depreciation**

| \$m (nominal)                                  | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|--|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Regulatory Depreciation per ACCC <sup>68</sup> | 14.12   | 15.53   | 17.09   | 18.80   | 20.75   | 14.44   | 12.49   | 13.09   | 13.71   | 14.35    |
| Indexation                                     | 5.00    | 4.70    | 4.43    | 4.09    | 3.69    | 3.25    | 3.01    | 2.75    | 2.48    | 2.19     |
| Straight line depreciation                     | 19.12   | 20.23   | 21.52   | 22.89   | 24.44   | 17.70   | 15.50   | 15.84   | 16.19   | 16.55    |

**Table 7.7 – Outturn CPI**

|            | Unit | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|------------|------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Actual CPI | %    | 2.84    | 2.69    | 2.48    | 2.49    | 3.98    | 2.07    | 4.51    | 1.46    | 3.05    | 2.50     |

**Table 7.8 – Indexation of the Capital Base 2002-2011**

| \$ '000 (nominal) | 2001/02 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11F |
|-------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|----------|
| Indexation        | 6,489   | 5,810   | 5,005   | 4,688   | 6,790   | 3,187   | 6,286   | 1,910   | 3,592   | 2,643    |

<sup>68</sup> ACCC 2002, *Final Decision*, Table 3.2



**Table 7.9 – Tax Asset Base as at 30 June 2011**

| <b>\$ '000 (nominal)</b> | <b>2001/02</b> | <b>2002/03</b> | <b>2003/04</b> | <b>2004/05</b> | <b>2005/06</b> | <b>2006/07</b> | <b>2007/08</b> | <b>2008/09</b> | <b>2009/10</b> | <b>2010/11F</b> |
|--------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|
| Opening TAB              | 22,263         | 18,004         | 14,751         | 14,542         | 12,186         | 10,394         | 8,791          | 7,841          | 6,959          | 6,353           |
| Additions                | 215            | 377            | 2,916          | 383            | 496            | 318            | 702            | 583            | 670            | 19,723          |
| Disposals                | -              | 2              | -              | 4              | 2              | 2              | 0              | 11             | 8              | -               |
| Tax Depreciation         | 4,473          | 3,629          | 3,124          | 2,735          | 2,286          | 1,918          | 1,652          | 1,454          | 1,267          | 2,085           |
| Closing TAB              | <b>18,004</b>  | <b>14,751</b>  | <b>14,542</b>  | <b>12,186</b>  | <b>10,394</b>  | <b>8,791</b>   | <b>7,841</b>   | <b>6,959</b>   | <b>6,353</b>   | <b>23,991</b>   |

**Table 7.10 – Opening capital base for the access arrangement period**

| <b>\$m (nominal)</b>           | <b>2001/02</b> | <b>2002/03</b> | <b>2003/04</b> | <b>2004/05</b> | <b>2005/06</b> | <b>2006/07</b> | <b>2007/08</b> | <b>2008/09</b> | <b>2009/10</b> | <b>2010/11F</b> |
|--------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|
| Opening capital base           | 228.5          | 216.1          | 202.0          | 188.6          | 170.8          | 153.6          | 139.4          | 131.0          | 117.6          | 105.7           |
| Conforming Capital Expenditure | 0.2            | 0.4            | 2.9            | 0.4            | 0.5            | 0.3            | 0.7            | 0.6            | 0.7            | 20.6            |
| Disposals                      | -              | (0.0)          | -              | (0.0)          | (0.0)          | (0.0)          | (0.0)          | (0.0)          | (0.0)          | -               |
| Depreciation                   | (19.1)         | (20.2)         | (21.5)         | (22.9)         | (24.4)         | (17.7)         | (15.5)         | (15.8)         | (16.2)         | (16.5)          |
| Indexation                     | 6.5            | 5.8            | 5.0            | 4.7            | 6.8            | 3.2            | 6.3            | 1.9            | 3.6            | 2.6             |
| Redundant Assets               | -              | -              | -              | -              | -              | -              | -              | -              | -              | -               |
| <b>Closing capital base</b>    | <b>216.1</b>   | <b>202.0</b>   | <b>188.6</b>   | <b>170.8</b>   | <b>153.6</b>   | <b>139.4</b>   | <b>131.0</b>   | <b>117.6</b>   | <b>105.7</b>   | <b>112.4</b>    |





## 8 Return on capital

### 8.1 Introduction

This chapter explains the parameters of the capital asset pricing model proposed for calculation of the weighted average cost of capital for the rate of return during the access arrangement period.

#### 8.1.1 Legal requirements

In determining its proposed estimate of the Weighted Average Cost of Capital (WACC) to apply to the AGP, regard must be given to the relevant provisions of the NGL and Rules. The overarching objective as set out in the NGL 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.<sup>69</sup>

Rule 87 provides that:

- 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) also provides that any forecasts or estimates are arrived at on a reasonable basis and must represent “the best forecast or estimate possible in the circumstances”.

Among other things, the revenue and pricing principles in the NGL provide that the service provider should be able to recover the efficient costs of providing the reference service, and earn a return that is commensurate with the risks involved in providing that reference service. While reference is made to meeting ‘benchmark levels of efficiency’ and applying a capital structure that ‘meets benchmark standards of gearing and other financial parameters’, there is no explicit reference to an ‘efficient benchmark service provider’ (as there is under the National Electricity

---

<sup>69</sup> National Gas Law section 23



Rules). However, it is well accepted regulatory practice to establish the required rate of return with reference to this 'efficient benchmark' firm.

Defining the efficient benchmark firm is likely to be more straightforward for major pipeline networks servicing a mix of residential, commercial and industrial gas consumers. However, the circumstances facing this pipeline are relatively unique. This is particularly an issue in establishing beta, which is discussed further below.

### 8.1.2 Approach

A WACC has been proposed for NT Gas that is considered to best meet the requirements of the NGL and Rules. In determining the assumptions to be applied to each parameter, regard has been given to relevant regulatory precedent, finance theory and commercial practice. Where relevant, reference is also made to the ACCC's 2002 Final Decision in relation to the AGP.<sup>70</sup>

Synergies Economic Consulting (Synergies) has been engaged to review certain aspects of the WACC to apply to NT Gas. An accompanying report by Synergies (the Synergies Report) is that Attachment G and addresses the following areas:

- beta;
- the debt risk premium;
- gamma; and
- the market risk premium (MRP).

A key concern for NT Gas is ensuring that the WACC promotes the efficient utilisation of, and investment in, the AGP (as required under the NGL pricing principles), recognising the difficult market conditions that have been experienced following the global financial crisis.

Analysis undertaken by Synergies in a report that accompanied the recent submission in relation to the APT Allgas network (*Estimating a WACC for the APT Allgas Distribution Network*) examined the contraction in the difference between the expected return on debt and equity that has been observed in regulated WACC determinations following the commencement of the global financial crisis. There is no logical reason why the expected return on debt would have risen relative to the expected return on equity (noting the significant increase in debt premiums that have been observed since the commencement of the crisis).

This observed contraction was seen to reflect the fact that the return on debt is set based on prevailing market rates at the time of the regulatory reset, whereas two of the main components of the return on equity, being beta and the MRP, are assumed to be more stable through time and hence tend to be based on long-term averages (noting the AER's decision to increase the MRP to be applied to electricity network

---

<sup>70</sup> ACCC 2002, *Final Decision*



businesses to 6.5 per cent in 2009 in acknowledgment of the impact of the global financial crisis).

Synergies observed that over the period between 1990 and 2007, the average difference between the return on debt (based on the UBS Australian Composite Index) and equity (based on the All Ordinaries Accumulation Index) was around 6.07 per cent. If this period was extended to include the abnormal market conditions experienced as a consequence of the global financial crisis, the difference was 2.85 per cent. However, this is based on actual observed returns and does not mean the investors' expected returns have fallen since the crisis - indeed the opposite would be expected.

Synergies suggests that a 'reasonableness' check of the difference between the estimated return on debt and equity requires that this difference should at least be around 4.5 per cent (which is the mid-point between 2.85 per cent and the pre-crisis average of 6.07 per cent). This is considered conservative given the average difference prevailing up until the crisis commenced was 6.07 per cent.

Overall, the analysis also highlighted the inherent uncertainties associated with the estimation of WACC and the particular caution that needs to be exercised when determining parameters that are "commensurate with prevailing conditions in the market for funds", in what has been such a difficult and uncertain period in world financial markets.

## **8.2 Risk-free rate**

It is recognised that in order to ensure that the rate of return reflects the prevailing conditions in the market for funds, it should be set as close as possible to the start of the regulatory control period (unless there is a significant economic shock or unexpected market event that effects the proposed averaging period). It is also noted that it is common practice for this averaging period to either be proposed by the regulated business for approval or confidentially advised in advance by the regulator. NT Gas' proposed averaging period is set out in confidential Attachment H.

For the purpose of calculating the indicative WACC estimate, the risk-free rate has been estimated in a manner that is consistent with standard AER practice, which is a twenty day average of the ten year Commonwealth Government bond yield (annualised). The average was taken over the twenty business days ending 30 November 2010. The resulting average was 5.48 per cent.

## **8.3 Gearing**

A debt to value ratio of 60 per cent is the most commonly applied assumption in regulatory decisions for gas pipeline networks and was also applied in the ACCC's 2002 Final Decision for NT Gas. Determinations have also generally assumed that



this gearing level is compatible with a BBB+ credit rating, including the AER's most recent decision for Jemena Gas Networks.<sup>71</sup>

It is unclear whether these assumptions will remain appropriate for NT Gas. This will largely depend on the certainty regarding the long-term cash flows for the pipeline, recognising the gradual depletion of the reserves in the Amadeus Basin and the competition from the potentially vast resources to the north of the continent.

For the purpose of setting indicative tariffs in this regulatory proposal, a gearing level of 60 per cent and notional credit rating of BBB+ has been assumed.

## 8.4 Debt margin

The estimation of the debt margin has proven one of the most difficult issues to resolve since the commencement of the global financial crisis, having regard to the need to develop the “best estimate or forecast possible in the circumstances” that is “commensurate with prevailing conditions in the market for funds”. With the relative paucity of data available to estimate the yields on long-term BBB+ debt<sup>72</sup>, debate has centred on:

- which data provider to source the information from (Bloomberg or CBA Spectrum); and
- how to estimate a ten year BBB yield using Bloomberg data, given the longest maturity for which yields are now published is seven years.

The most recent development is CBA Spectrum's decision to cease publication of its corporate bond yields, which highlights the difficulties that are currently faced. The data that has previously been used by the AER to extrapolate the Bloomberg seven year yield, being its seven and ten year AAA corporate bond yields, are now also no longer published.

The accompanying report by Synergies examines the impact of these developments and the AER's proposed response, as outlined in its recent Final Determination for the Victorian electricity network businesses (the Victorian Final Decision).<sup>73</sup> This decision is of particular interest for this review as it is expected that the AER will seek to apply this same approach to both gas and electricity network businesses, noting that the requirements in relation to the estimation of a debt margin for the latter are more specific under the National Electricity Rules.

---

<sup>71</sup> Australian Energy Regulator 2010, *Jemena Gas Networks, Access Arrangement Proposal for the NSW Gas Networks, 1 July 2010 – 30 June 2015*, June, p 278

<sup>72</sup> Bloomberg does not publish separate estimates for BBB and BBB+ (all BBB bonds are included in a single sample). References in this Chapter to 'BBB' in the context of Bloomberg estimates is assumed to include BBB+

<sup>73</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October





#### 8.4.1 Data sources

NT Gas considers that the preferable approach to estimate the debt margin, until recently, has been to take an average of Bloomberg and CBA Spectrum yields. This was for a number of reasons, including recognising: the inherent difficulties facing both data providers given the lack of market data; the lack of information that is available regarding the methodology used by each service to construct its yield curves; and the fact that both data providers are independent, reputable organisations with specific expertise in financial markets.

While the cessation of publication of the CBA Spectrum data is unfortunate (although noting that it was not accessible to all as it was only available to CBA customers), NT Gas strongly disagrees with the AER's solution adopted in the Victorian Final Decision which was to reference a single bond issue along with the Bloomberg data. This single bond issue is the APA Group's own issue, being the ten year BBB APT bond.

From the NT Gas' perspective, the issue is not whether the APT bond itself is an appropriate proxy (noting that the requirements in relation to estimating the debt margin are more specific under the National Electricity Rules than the Rules), but simply the reliance that has effectively been placed on a single issue. While the AER reduced the weight that would be applied from 50 per cent to 25 per cent in the Victorian Final Decision, this weighting still results in material reliance being placed on this one instrument.

Apart from the problems that putting so much weight on a single bond issue presents (which are discussed further below), NT Gas does not accept the reasons put forward by the AER to justify this inclusion. For example, NT Gas disagrees with the AER that CBA's decision to no longer publish its fair value estimates creates any additional concerns regarding the transparency of the Bloomberg estimates "and the prudence of now relying on them as the sole or primary source of information for determining the DRP."<sup>74</sup> These concerns already existed with both data providers, however the AER has been comfortable relying on one data source in the past depending on the outcomes of its testing methodology.

The AER also suggests that the Australian Competition Tribunal's (the Tribunal's) decision in relation to ActewAGL provides further support for relying on the APT issue as it recommended consideration of "alternative sources of information". The main context for the Tribunal's decision was consideration of two alternative, reputable data providers that construct yield curves using available market data. It could not be construed that having regard to "alternative sources" supports placing a 25% weighting on a single bond issue. This is particularly the case given one of the key conclusions made by the Tribunal was that the sample the AER had used to assess the alternative data sources was too limited (and not sufficiently representative of the required term to maturity):

---

<sup>74</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 493



In the Tribunal's view, it is not reasonable to decide which of three non-linear curves best fits a set of data that consists of only five points, especially when those points cover little more than half of the range of the independent variable, namely the term to maturity.<sup>75</sup>

More importantly, in NT Gas' opinion the key question here is why the APT bond is an "alternative" data source. As a ten year BBB+ corporate bond issue it is part of the available market data that Bloomberg could currently be utilising. As at the end of October 2010, the APT bond was not referenced in Bloomberg's BBB sample. NT Gas is not aware as to whether it has been used by Bloomberg in constructing its BBB curve since it was issued in April 2010. However, it remains possible that it will be included in the future. If it is included, the AER's methodology will result in double counting.

The most likely reason why the APT bond is not included in Bloomberg's sample is because the bond is not actively traded. APA Group have advised NT Gas that its debt is currently held by thirteen institutions that have purchased this debt as part of a long-term 'buy and hold' strategy, as the characteristics of the business meet their specific needs. In this case, this lack of liquidity is not a negative; it simply reflects the nature and composition of the market participants that hold this paper and their reasons for holding it.

The issue of liquidity is explored in more detail in the Synergies report. It notes that most of the yields referenced in the Bloomberg sample are indicative prices and a bond will not be included if Bloomberg does not consider that indicative price to be a reasonable approximation of the actual price.

As highlighted by Synergies, the liquidity of an instrument (whether that be a bond or a share) is a critical factor in establishing the extent to which the price of that instrument fully reflects current information, including the expectations of market participants regarding the required return on ten year BBB+ debt. This is essential if the estimate is to meet the requirement of being the "best estimate or forecast possible in the circumstances" that is "commensurate with prevailing conditions in the market for funds".

The AER has not considered the prospect of the APT bond being included in the Bloomberg sample. It has also not questioned why it may not be included, noting that its own testing methodology subjects the issues that are included in Bloomberg's sample to some scrutiny (such as the debate regarding the inclusion of the BBI bond). The AER is placing considerable reliance on the yield on the APT bond being representative of the ten year cost of funds for a BBB+ rated corporate borrower. Indeed, the AER has gone as far as suggesting that:

---

<sup>75</sup> Australian Competition Tribunal 2010, Application by ActewAGL Distribution [2010] ACompT 4, para 39



...Bloomberg's 7 year BBB fair value estimate is likely to overstate the relevant benchmark corporate bond yield as evidenced by comparing Bloomberg's fair value curve with the APT bond.<sup>76</sup>

The AER acknowledged that the debt risk premium estimates derived from Bloomberg and the APT bond yield did diverge in August 2010, with the latter increasing and the former decreasing. This is seen as supporting its decision to reduce the APT bond weighting to 25 per cent "as it may not reflect factors affecting bonds of the same credit rating".<sup>77</sup> However, a 25 per cent weighting is still material.

Reference is also made to a detailed analysis undertaken by CEG as part of the submissions made to the AER by the Victorian distribution network businesses.<sup>78</sup> CEG concluded that the APT bond has an unusually low estimated debt risk premium for its credit rating and that sole reliance should be placed on the Bloomberg estimate.

There is another important reason why it is not considered appropriate to reference the APT bond and that is because as it was issued by NT Gas' majority owner, the AER is effectively referencing NT Gas' actual cost of funds in estimating the debt risk premium. Established regulatory practice – and the approach that has been explicitly adopted by the AER – is to use a benchmark approach.

The key rationale for this is that it is consistent with the principle of incentive regulation. Referencing a regulated firm's actual cost of debt in setting the debt risk premium could reward inefficient financing practices. It could also remove any of the benefits that would otherwise accrue to the firm from adopting a particularly efficient financing strategy. This removes any incentive to outperform the benchmark. Having the incentive to pursue efficiency is in the long-term interests of consumers.

The APA Group has advised that the APT bond issue was highly opportunistic and may not be able to be repeated in the short to medium-term, at least for a ten year tenor. The APT issue was also recently awarded the KangaNews Australian Domestic Corporate Market Deal of the Year and Finance Asia magazine's award for best local bond deal. As highlighted by Synergies, this may suggest that this deal was considered particularly innovative by market participants in what has been a difficult year for BBB-rated corporate issuers (and indeed any corporate).

To the extent that this deal was opportunistic in what has been a very uncertain environment for domestic corporate issuers, it will be difficult to replicate this outcome, even for the 'efficient benchmark firm'. That is, this deal may be more of an outlier than indicative of the benchmark cost of funds (noting that Bloomberg has not included it in its sample).

---

<sup>76</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 509

<sup>77</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 514

<sup>78</sup> CEG 2010, *Use of the APT Bond Yield in Establishing the NER Cost of Debt, A Report for Victorian Distribution Businesses*, October



NT Gas is therefore concerned that referencing the APT bond to estimate the debt margin that will apply to the AGP removes the benefit that would otherwise accrue to the business because it was able to implement an efficient and innovative financing structure. The APA Group is also funding an asset base of some \$5 billion in total. This is likely to well exceed the size of the 'efficient benchmark firm' and is some fifty times the size of the AGP's capital base.

Further, to the extent that this deal would be difficult to replicate (let alone outperform), it should not be used to determine the benchmark cost of funds for NT Gas or any regulated business. It is evident that this deal was opportunistic and potentially unique. Using it to establish the benchmark does not provide a realistic incentive to improve efficiency relative to that benchmark, which is not in the long-term interests of consumers. In conclusion, the NT Gas is strongly of the view that to the extent that the yield on the ten year BBB+ APT bond is used to determine the debt risk premium, it should only be because that bond is already in the sample referenced by Bloomberg to derive its fair value estimate. A single bond issue should not be used as an 'additional' source of data alongside an estimate derived by a reputable independent institution using a sample of bonds that are trading in the market. If it does end up in the Bloomberg sample, it will result in double counting. If it is not referenced by Bloomberg, the question that should be asked is why. The likely answer to this question is that the bond is currently considered an outlier, rather than an estimate that is indicative of the prevailing cost of funds for the 'efficient benchmark firm'.

If any reliance is to be placed on a single bond to derive the debt risk premium – let alone giving it a 25 per cent weighting – it is essential that there is adequate liquidity in that instrument. If there is limited or no turnover, the quoted yields on that bond will not necessarily reflect current information, or synthesise the expectations of market participants of the future debt risk premium. This in turn means that the estimate will not meet the requirement of being the "best estimate or forecast possible in the circumstances" that is "commensurate with prevailing conditions in the market for funds".

#### 8.4.2 Extrapolating the Bloomberg seven year BBB yield

As outlined above, previously the AER extrapolated the Bloomberg BBB yield using the seven and ten year AAA corporate bond yields. Bloomberg ceased publishing this data in June 2010. It had originally proposed to reference the Commonwealth Government Securities (CGS) curve however has recognised that this will result in the debt risk premium being constant between seven and ten years.<sup>79</sup> In the Victorian Final Decision it therefore reverted to the use of the AAA corporate bond yields.

It is not clear if the AER intends to continue to reference these AAA corporate bond yields for future decisions but if it does, the NT Gas questions how this 'old' data can continue to be used to construct the "best estimate or forecast possible in the circumstances" that is "commensurate with prevailing conditions in the market for

---

<sup>79</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 510



funds". It is simply not considered practical to combine current estimates for the risk-free rate and Bloomberg seven year bond yield with the AAA corporate bond data when the latest available data is June 2010. The only circumstances under which it could be used is if Bloomberg resumes publication of that data.

Consistent with the APA Group submission for APT Allgas, NT Gas considers that extrapolation based on the Bloomberg five and seven year yield remains the most appropriate method (and indeed is potentially now the only option remaining if current market data is to be used). As set out in the accompanying Synergies report, it has compared the resulting ten year BBB yield derived using this method when the actual ten year BBB yields were still published by Bloomberg, and the difference in the estimates are minimal. While this analysis was done prior to the global financial crisis, it is still considered a reasonable and defensible approach, particularly in the absence of other robust alternatives that use current market data.

### 8.4.3 Proposed debt margin

The debt margin has been estimated for NT Gas using Bloomberg data, extrapolating the seven year BBB yield based on the difference between the five and seven year yields (annualised). A twenty day averaging period to 30 November 2010 has been used. The resulting estimate is 546 basis points.

This is materially higher than margins observed earlier this year, with Bloomberg's seven year fair value yield at nearly 9.5 per cent at the end of November, which is close to the highest level that these reported yields have been at since the commencement of the global financial crisis. The debt margin that will be used to set final tariffs will depend on the yields prevailing over the chosen averaging period.

## 8.5 Market risk premium

Since the finalisation of its WACC Statements that set out the methodology and parameters that the AER proposes to apply to electricity transmission and distribution network service providers,<sup>80</sup> the AER has applied a market risk premium of 6.5 per cent in both electricity and gas decisions. It has applied this value in response to the impact of the global financial crisis and has indicated that if and when market conditions appear to have stabilised, it is likely to revert to what it considers to be the long-term average of 6 per cent. In the Victorian Final Decision, it stated:

While there is evidence that Australia's economic conditions have improved since the GFC, the AER remains cautious to the extent of this recovery citing the views from prominent economic bodies' warning of the fragility of the recovery in the global

---

<sup>80</sup> Australian Energy Regulator 2009, *Electricity Transmission and Distribution Network Service Providers: Statement of the Revised WACC Parameters (Transmission)*, *Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)*



economy. Furthermore, conditions in global capital markets remain uncertain as the aftermath of the GFC continues to be felt and resolved.<sup>81</sup>

Consequently, the AER considers it appropriate to maintain the value of 6.5 per cent until there is persuasive evidence that market conditions have stabilised.

The accompanying report by Synergies concludes that despite the signs of improvement in the world economy, there are a number of significant risks that remain. Notwithstanding the Australian economy's relative resilience to some of the events that have seen a more significant deterioration in conditions in other major economies, uncertainty continues to be the pervading theme. This is particularly the case in the financial markets, where credit conditions remain tight and yields on corporate debt high (and not showing any consistent signs of returning to anywhere near pre-crisis levels).

It therefore continues to be premature to conclude that the risks of any further major downturn in the world economy have abated. An MRP of 6.5 per cent has therefore been assumed and consistent with the view expressed in the APT Allgas submission, this assumption is considered conservative.

## 8.6 Beta

### 8.6.1 Establishing the characteristics of the 'efficient benchmark firm'

As outlined above, parameters such as beta are established with reference to the 'efficient benchmark firm'. The profile of the efficient benchmark firm is relatively straightforward to establish for a typical pipeline network business that supplies to a mix of residential, commercial and industrial gas consumers. However, this profile is not representative of NT Gas.

The 1,629 kilometre pipeline was constructed to deliver gas from the Amadeus Basin near Alice Springs through to Darwin. There are a number of delivery points along the pipeline that supply gas to be used for electricity generation and mining operations. There is only one major customer, the PWC, whose access current gas transportation agreement expires in 2011. A replacement contract is not in place. As the only major customer, PWC has significant countervailing buyer power.

The reserves in the Amadeus Basin were deemed inadequate to meet PWC's demand for the term of its original contract period. It has subsequently switched its sources of supply to the Blacktip field, which enters the pipeline at Ban Ban Springs. Alternative emergency reserves at the northern end of the pipeline (close to the sources of underlying demand) have also been sourced.

---

<sup>81</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 65





### 8.6.2 Implications for systematic risk

The AGP's circumstances are unique and accordingly it is difficult to make any direct comparisons with other regulated gas pipelines. The AGP currently services only one major customer with significant countervailing power. This customer no longer sources the bulk of its supply from the Amadeus Basin and instead is sourcing gas from reserves located near the northern tip of the pipeline. NT Gas therefore has no market power.

The key issue for NT Gas that makes it particularly unique compared to the average regulated gas pipeline is stranding risk. The reserves in the Amadeus Basin are depleting and face significant competition from the vast supplies to the north of the continent. It is unknown whether the existing capacity will be partially or fully contracted or whether NT Gas will be able to fully recover a return on, and return of, capital, notwithstanding that accelerated depreciation has been applied to 2011.

As highlighted in the Synergies report, this risk is not compensated via the rate of return because it is asymmetric in nature. The Capital Asset Pricing Model assumes that returns are normally distributed. The extent to which this risk is systematic in nature depends on the extent to which the key drivers of this risk are correlated with domestic economic activity. In the ACCC's 2002 Final Decision it recognised the existence of stranding risk although considered it to be non-diversifiable. It concluded that it was:

...a unique or specific risk, and as such, should be accommodated in the cash flows rather than the CAPM formula.<sup>82</sup>

To the extent that stranding risk does have a systematic or non-diversifiable component, it should still be compensated in the cash flows. This is because CAPM assumes that returns are normally distributed.

### 8.6.3 Implications for beta

The Rules require that the rate of return is "commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services" and that any estimate is the "best forecast or estimate possible in the circumstances". Synergies has examined the market data that is available and has concluded that it is not sufficiently reliable to support any revision to the equity beta estimate from the value of 1 that was previously determined by the ACCC.

The key issue for NT Gas is its exposure to the risk of asset stranding. This risk is not compensated via beta. Instead, it should be addressed by way of a cash flow adjustment. There is no established AER precedent for this risk at this stage. The materiality of NT Gas' exposure to this risk will largely depend on the proportion of capacity that is contracted, if it is contracted (noting that there is no replacement contract in place at the current time), as well as the extent to which the prices that can be charged enable the full costs of the pipeline to be recovered.

---

<sup>82</sup> ACCC 2002, *Final Decision*, p 91



An equity beta of 1 is therefore proposed by NT Gas.

## 8.7 Gamma

The estimation of gamma has proven highly contentious since the AER determined that it would apply a value of 0.65 to electricity transmission and distribution network businesses in its WACC Statements. This culminated in an appeal to the Australian Competition Tribunal by ETSA Utilities, Ergon Energy and ENERGEX, which was heard in October 2010. The outcomes of this appeal have not yet been finalised, primarily in relation to the value of franking credits (or theta). NT Gas acknowledges that this final outcome will be a key driver of the AER's future position in relation to gamma.

The two key inputs to be estimated are:

- the distribution rate; and
- the value of franking credits (theta).

Each of these is addressed in turn below.

### 8.7.1 Distribution rate

In the Victorian Final Decision, the AER has recognised that the empirical evidence showing a distribution rate of 70 per cent reflected the average distribution rate rather than an annual rate. This in turn means that “the proportion of retained credits subject to time value loss is greater than previously conceived.”<sup>83</sup> However, as it still considers that there are “strong theoretical grounds” that the retained credits have some value, it still considers that the distribution rate is somewhere between 70 per cent and 100 per cent.

NT Gas disputes the assumption of a distribution rate that is higher than 70 per cent, unless there is robust empirical evidence that supports that assumption. It questions whether on other matters, the AER would accept an estimate submitted by a regulated business that it had put forward solely on the basis of “strong theoretical grounds”, without any supporting evidence. If that burden of proof is placed on the regulated business, it should similarly rest with the AER in supporting any assumed value for retained credits. In the absence of such evidence, and given the asymmetric consequences of regulatory error, the value of retained credits should be assumed to be zero.

### 8.7.2 The value of theta

NT Gas challenges the AER's previously adopted position in relation to theta, including its reliance on tax statistics. Consistent with arguments outlined in the

---

<sup>83</sup> Australian Energy Regulator 2010, *Victorian Electricity Network Service Providers, Distribution Determination 2011-2015: Final Decision*, October, p 537





submission by APT Allgas, NT Gas considers that a range of studies should be relied upon to estimate theta, however these studies should be limited to market-based analyses. This is because the value of theta can only be derived from market data.

The evidence that NT Gas considers is relevant, as set out in the Synergies report, is summarised in Table 8.1 over the page.

This evidence shows that zero should at least be included within the bounds of a reasonable range. Excluding the Beggs and Skeels estimate for the 1986-88 subperiod, the highest value for theta is 0.57 (which is the number previously relied upon by the AER). This is considered a reasonable 'upper bound'.

### 8.7.3 Proposed value of gamma

NT Gas consider that the appropriate range for theta is between zero and 0.57. Applying a distribution rate of 70 per cent results in a range of between 0 and 0.4 for gamma. The mid-point of that range is 0.2.

Recognising the uncertainty surrounding the estimation of theta, the NT Gas considers that a value of gamma of 0.2 is conservative. A value of 0.2 has therefore been proposed for NT Gas.

## 8.8 Taxation rate

A corporate tax rate of 30 per cent has been proposed, consistent with regulatory precedent.

## 8.9 Forecast inflation

NT Gas proposes an inflation estimate of 2.5 per cent. This value is considered the most appropriate estimate for inflation over a ten year forecast horizon. This is because the Reserve Bank's target range for inflation is between 2 per cent and 3 per cent and it has consistently demonstrated an intention to maintain inflation within this target band.

NT Gas also raises concerns with any future reliance on indexed bonds to estimate inflation. The primary concern here is liquidity. The implications of low liquidity for forming any reliable view regarding expectations of future interest rates were discussed above in the context of estimating the debt margin. These issues are equally relevant here.

**Table 8.1 – Studies that can be referenced in valuing  $\theta$**

| Study   | Methodology  | Time Period for Estimation | Value of franking credits (V)    |
|---|--|----------------------------|----------------------------------|
| Hathaway and Officer (2004) <sup>a</sup>      | Dividend drop-off  | 1988-2002                  | 0.5                              |
| Bellamy & Gray (2004) <sup>b</sup>            | Dividend drop-off (adjusted)                                     | 1995-2002                  | 0                                |
| Cannavan, Finn & Gray (2004) <sup>c</sup>     | Analysis of futures and physical market (no arbitrage framework) | Pre-45 day rule (1997)     | Up to 0.5 (high-yielding stocks) |
| Beggs & Skeels (2006) <sup>d</sup>            | Dividend drop-off  | 1986-1988                  | 0.75                             |
|   |  | 1989-1990                  | 0.45                             |
|   |  | 1991                       | 0.38                             |
|   |  | 1992-1997                  | 0.2                              |
|   |  | 1998-1999                  | 0.42                             |
|   |  | 2000                       | 0.128                            |
|   |  | 2001-2004                  | 0.57                             |
| SFG Consulting (2010) <sup>e</sup>            | Dividend drop-off, based on Beggs & Skeels methodology           | 1 Jul 97-30 Jun 99         | 0.24                             |
|   |  | 1 Jul 99 -30 Jun 00        | 0.36                             |
|   |  | 1 Jul 00-30 Jun 06         | 0.23                             |
| Feuerherdt, Gray and Hall (2010) <sup>f</sup> | Dividend drop-off, hybrid securities                             | Pre-1997 (45 day rule)     | 0                                |
|   |  | Post 1997 – 2000           |                                  |
|   |  | Post 2000                  |                                  |

<sup>a</sup> N. Hathaway and R. Officer (2004). The Value of Imputation Tax Credits: Update 2004, Unpublished Working Paper, Capital Research Pty Ltd

<sup>b</sup> D. Bellamy & S. Gray (2004). Using Stock Price Changes to Estimate the Value of Dividend Franking Credits, Working Paper, University of Queensland

<sup>c</sup> D. Cannavan, F. Finn and S. Gray (2004). The Valuation of Dividend Imputation Tax Credits in Australia. Journal of Financial Economics, 73, 167-197

<sup>d</sup> D. Beggs & C. Skeels (2006). Market Arbitrage of Cash Dividends and Franking Credits. Economic Record, 82, 239–252

<sup>e</sup> SFG Consulting (2010). Further Analysis in Response to AER Draft Determination in Relation to Gamma, Prepared for ETSA Utilities, February

<sup>f</sup> C. Feuerherdt, S. Gray and J. Hall (2010). The Value of Imputation Tax Credits on Australian Hybrid Securities, International Review of Finance, 10:3, 365-401



## 8.10 Debt raising costs

NT Gas proposes to apply the method and table of estimates used by the AER, as recently published in its decision for the Jemena Gas Networks, to estimate its debt raising costs.<sup>84</sup> Based on its opening capital base of \$112 million and applying a 60 per cent gearing ratio, its total debt will be approximately \$60 million. Reference is therefore made to the indicative allowance for one bond issue in the AER's table, which is 10.8 basis points per annum. Debt raising costs of 10.8 basis points per annum is therefore proposed.

NT Gas considers that the simplest and most transparent approach to apply is to include the allowance for debt raising costs in the cost of debt. It has therefore added this margin to the cost of debt rather than as part of its operating expenditure allowance.

## 8.11 WACC estimate

Based on the parameter estimates set out above, the resulting indicative estimate of the WACC to apply to NT Gas is summarised in Table 8.2 below.

**Table 8.2 – WACC estimate**

| Parameter                    | Estimate      |
|------------------------------|---------------|
| Risk-free rate               | 5.48%         |
| Forecast inflation           | 2.50%         |
| Debt to value                | 60%           |
| Debt margin                  | 5.46%         |
| Debt raising costs           | 0.108%        |
| MRP                          | 6.5%          |
| Gamma                        | 0.2           |
| Equity beta                  | 1             |
| Cost of equity               | 11.98%        |
| Cost of debt                 | 11.05%        |
| <b>Post tax nominal WACC</b> | <b>11.42%</b> |

As outlined above, based on Synergies' analysis, if regard is given to the average cost of debt and equity prevailing since 1990, the difference between the cost of debt and equity should be between 4.5 per cent and 6 per cent. This is considered

<sup>84</sup> Australian Energy Regulator 2010, *Jemena Gas Networks, Access Arrangement Proposal for the NSW Gas Networks, 1 July 2010 – 30 June 2015*, June, p 278



conservative because 6 per cent is the average difference observed prior to the crisis, whereas the 4.5 per cent partially reflects the compression in returns experienced following the crisis.

The difference implied by the above estimates is less than 1 per cent, which is materially below this range and the post-crisis average. The cost of debt has been estimated using current market data. The cost of equity reflects standard regulatory assumptions and methodologies. Any further adjustments to the cost of equity inputs (such as a reduction in the equity beta) will further compress this difference.

To the extent that the cost of debt is commensurate with prevailing conditions in the market for funds, and there is no reason to expect that equity holders would require a lower return relative to debt holders, any such compression risks materially under-compensating equity investors. Ultimately, this could compromise the National Gas Objective, which is to encourage efficient utilisation of, and investment in, the pipeline network.



## 9 Operating expenditure

This chapter sets out operating expenditure undertaken in the earlier access arrangement period and forecast operating expenditure for the access arrangement period, and provides explanations for actual and forecast operating expenditure by reference to the Rules.

### 9.1 Operating expenditure categories

As defined under Rule 69, operating expenditure for the purposes of price and revenue regulation under the Rules means:

... 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.<sup>85</sup>

For the purposes of the access arrangement revision proposal NT Gas classifies its operating expenditure in the following categories:

- *Operations and Maintenance*, which is direct expenditure associated with operating and maintaining the pipeline, pipeline right of way, pipeline facilities, compressor station, SCADA and communications systems and regulation, metering and gas measurement equipment. Other activities in this category include pipeline integrity management, pipeline facility upgrading and training for emergency response;
- *Overheads*, which includes expenditure relating to insurances, directors fees, regulatory activities, compliance, support costs for personnel and training, legal, accounting, taxation, government levies, fees and charges and central head office costs; and
- *Sales and Marketing*, which includes expenditure relating to advertising and promotion of gas transportation services, investigation and feasibility studies for potential gas consuming projects, and commercial negotiations relating to gas transportation services.

NT Gas notes that the Access Arrangement Information in place for the earlier access arrangement period refers to the *Overheads* category as *Administration and General*. The *Overheads* category used in this access arrangement revision proposal, along with the other operating expenditure categories, are identical to those used in the earlier access arrangement period to ensure consistency when

---

<sup>85</sup> This definition differs in important respects from that in clause 8.36 of the former National Gas Code which defines non-capital costs as:

... the operating, maintenance and other costs incurred in the delivery of the Reference Service. Non Capital Costs may include, but are not limited to, costs incurred for generic market development activities aimed at increasing long-term demand for the delivery of the Reference Service.



comparing actual expenditure against the forecasts used to derive tariffs in the earlier access arrangement period, and comparing past and future expenditure in this access arrangement period. Any difference in categories is therefore in name only and does not reflect an underlying difference in the allocation of costs to those categories.

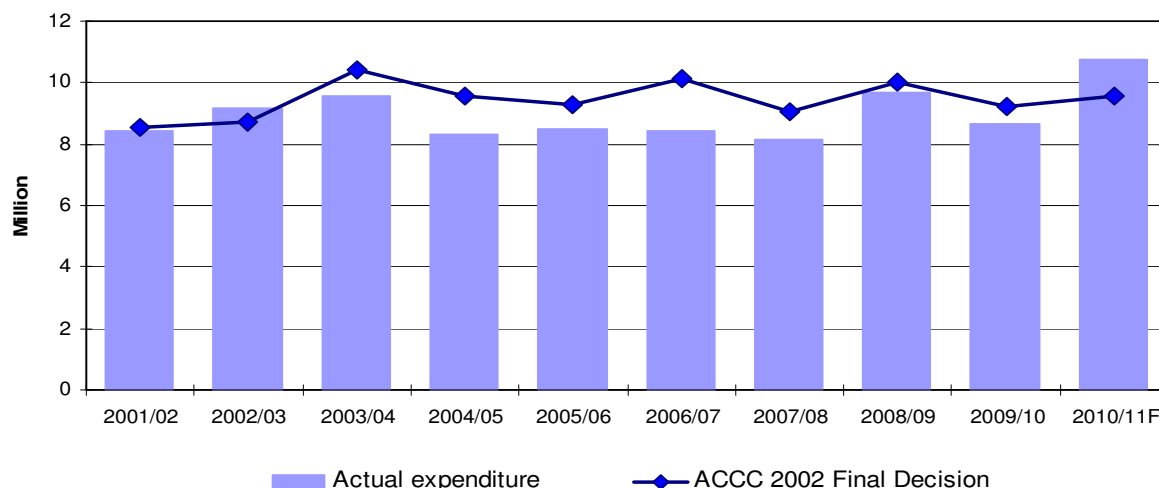
NT Gas does not use these categories in its actual accounting and therefore some judgement has been applied in categorising historic and forecast expenditure into these categories.

## 9.2 Operating expenditure over earlier access arrangement period

The operating expenditure allowed by the ACCC in the earlier access arrangement period is shown in Table 9.6 at the end of this chapter (in 2009/10 dollars). The ACCC's 2002 Final Decision approved forecast operating expenditure as proposed by NT Gas in its revised proposal made in response to the ACCC's Draft Decision.<sup>86</sup>

Table 9.6 also sets out actual and forecast operating expenditure incurred over the earlier access arrangement period, and compares incurred expenditure to that approved by the ACCC in its Final Decision in constant terms. This is shown graphically in Figure 9.1 below.

**Figure 9.1 – Total operating expenditure comparison to forecast over the earlier access arrangement period**



NT Gas' total operating expenditure over the period is expected to be \$89.7 million. This is \$4.8 million (or 5 per cent) below that approved by the ACCC in 2002. This minor deviation is attributable to variations from forecast as follows:

<sup>86</sup> ACCC 2002, *Final Decision*, p 100



- Operations and maintenance expenditure \$0.9 million below the earlier access arrangement allowance;
- Overheads being \$3 million below the earlier access arrangement allowance; and
- Sales and Marketing expenditure \$0.9 million below the earlier access arrangement allowance.

While the total deviation from the expenditure forecast approved by the ACCC is not significant, the profile of actual expenditure over the period shows some significant deviations from that originally approved by the ACCC. These deviations are discussed in the following sections.

### 9.2.1 Operations and maintenance

As can be seen from Table 9.6 at the end of this chapter, up until 2010/11, operating and maintenance expenditure tracked close to the forecast. This reflects the largely 'routine' nature of expenditure in this category, with few deviations from the steady annual expenditure on pipeline maintenance and integrity works.

Deviations from the forecast largely relate changes in scheduled intelligent pigging of the pipeline, and salary and labour costs.

#### *Intelligent pigging*

Intelligent pigging costs included in the earlier access arrangement period were based on previous costs for pigging this section of the pipeline on the following schedule:

- Mataranka to Darwin City Gate - 2003/04 forecast at \$1.8 million (\$2009/10);
- Palm Valley to Mataranka - 2006/07 forecast at \$0.9 million (\$2009/10); and
- Mereenie spurline - 2008/09 forecast at \$0.7 million (\$2009/10).

NT Gas was able to achieve significant cost savings compared to the forecast through alternative contracting arrangements with a competing provider, and taking advantage of reductions in the costs of the intelligent pigging tool compared to previous surveys.

In total, pipeline pigging costs were \$1.73 million (\$2009/10). This accounts for 36 per cent of the deviation from forecast costs in this category over the earlier access arrangement period.

Savings in intelligent pigging costs achieved in the earlier access arrangement period are reflected in forecast pigging costs in 2012/13 and 2015/16, discussed further in section 9.3.1 below.



### *Salary and labour*

Over the earlier access arrangement period NT Gas experienced significant deviations from forecast in the various components of the labour forecast, which largely offset each other to deliver actual labour costs similar to that forecast.

Driving labour costs down, NT Gas had difficulty recruiting and retaining staff over the period, driven in particular by competition with the mining and utilities sectors. NT Gas' turnover rate was 18 per cent over the earlier access arrangement period, higher than the NT average of 15 per cent. Coupled with this turnover rate were relatively long lead times in the recruitment of replacement staff (often requiring relocation of staff to NT), that meant on average NT Gas experienced a five per cent saving in total labour costs associated with unfilled positions over the period.

In addition, the high number of unfilled positions over the period contributed to a relatively finite labour resource that was able to be allocated to work on both regulated and unregulated assets under the responsibility of NT Gas. In this environment, customer-driven work associated with the MacArthur River Pipeline in the early part of the earlier access arrangement period, and the connection of the Weddell/ Wickham Point pipeline and the Bonaparte Gas Pipeline in the later part of the earlier access arrangement period was undertaken, largely within the existing labour resources. All costs associated with these projects (including labour costs) were allocated to unregulated assets and are therefore not included in recorded costs for the AGP.

In practice, this customer-driven work on unregulated assets has meant that the relative allocation of NT Gas labour costs to the AGP compared to other assets is lower than forecast. The scope of work undertaken on the regulated pipeline, however, remained largely in line with forecast, with some limited re-scheduling of non-essential routine work that was considered able to be rescheduled over the short-term without sacrificing pipeline integrity. The prioritisation of customer-initiated work over otherwise deferrable maintenance expenditure (at least in the short term) is consistent with NT Gas' operating philosophy and approach to risk management.

Working against these drivers for lower labour costs, salary costs per employee increased substantially over the period, contributing to higher costs for this component of labour compared to the forecast. The same factors as highlighted above led to this outcome - high staff turn-over, competition for labour resources with the utility and the mining industries and locational factors. The actual average labour cost increase was 4.34 per cent between 2006 and 2010.

NT Gas expects these trends to continue over the access arrangement period, particularly as the mining sector continues to recover after the global financial crisis. As noted above, however, the current slight downturn in demand for labour resources in the mining industry has allowed NT Gas to schedule the delivery of the forecast 2010/11 and 2011/12 program of special projects, discussed in the capital expenditure chapter.





### 9.2.2 Overheads

Overheads expenditure over the earlier access arrangement period was below forecast expenditure.

The corporate overheads allocation included in the forecast was based on the full recovery of the allocation of corporate overheads from the then majority owner of NT Gas (AGL). A commercial decision was subsequently made to allocate less corporate overhead to NT Gas because the existing negotiated service contract did not allow the recovery of these costs through tariffs. As a result, the remaining unallocated NT Gas corporate costs were incurred at a corporate level.

Forecast corporate overheads costs discussed below in section 9.3.2 are based on a full allocation of APA Group corporate costs allocated to NT Gas, as these are legitimate costs associated with the operation of the business that should be recovered from users of the reference service. These costs are also expected to be recovered under the negotiated service contract in the future.

### 9.2.3 Sales and marketing

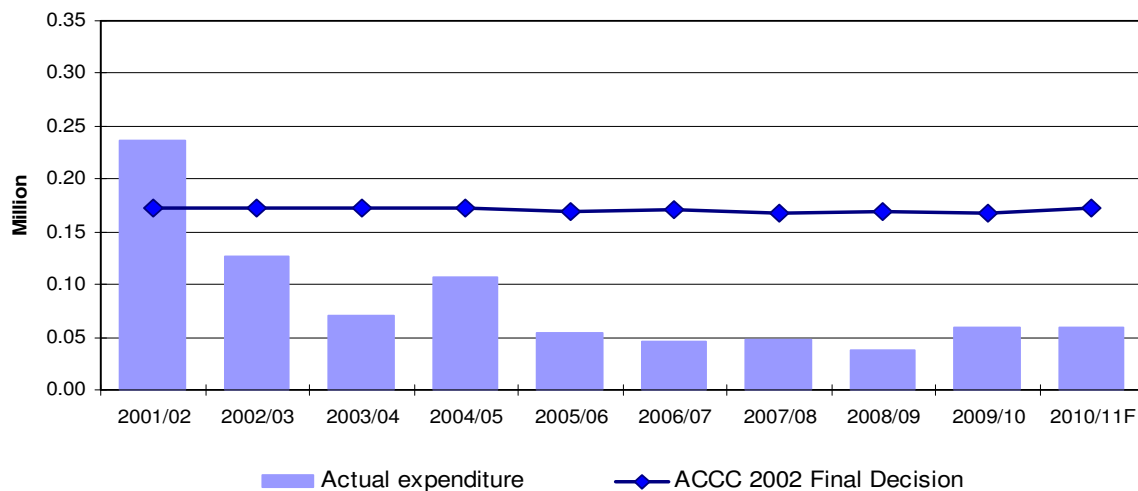
Sales and Marketing expenditure over the earlier access arrangement period was below forecast expenditure, as shown in Figure 9.2 below.

The underspend is entirely driven by the availability of gas and firm capacity on the pipeline. As described in section 6.2.2 above, declining production from the Mereenie field meant that from early in the period there was a significant scarcity of gas, culminating in gas shortfalls between September 2007 to August 2009. This scarcity was not anticipated when the earlier access arrangement was approved as at the time PWC had expected to be able to continue to drill and prove reserves out of the Amadeus Basin. When early investigations and drilling did not uncover additional reserves in the basin, PWC decided to concentrate on developing an alternative source of gas.

Under these conditions, sales and marketing activity decreased significantly, with expenditure limited to responding to customer enquiries and the preparation of term sheets for potential interruptible gas supply contracts, which ultimately did not lead to significant contracts. The marketing of gas ceased completely in this period. Expenditure is expected to return to the previous trend in the access arrangement period, as discussed further below in relation to forecasts in this category.



**Figure 9.2 – Sales and marketing operating expenditure comparison to forecast over the earlier access arrangement period**



### 9.3 Forecast operating expenditure

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 operation.

The AER's discretion under this rule is limited such that the AER must not withhold its approval of proposed operating expenditure if it is satisfied that the proposal complies with the requirements of the law and is consistent with Rule 91. All forecasts and estimates must also comply with Rule 74.

NT Gas has forecast its operating expenditure to ensure ongoing compliance with its regulatory obligations discussed in chapter 3, and in line with the planning and asset management processes and procedures set out in chapter 4. There are no contingency allowances included in the operating expenditure forecast. NT Gas notes that there is a material risk that some estimates will be too low owing to uncertainties in forecasting costs accurately, particularly in the later years of the access arrangement period.

NT Gas considers that its forecast operating expenditure is consistent with Rule 91 as being prudent and efficient expenditure. NT Gas further considers that its forecast has been arrived at on a reasonable basis and is the best possible in the circumstances, in accordance with Rule 74.



### 9.3.1 Operations and maintenance expenditure

#### *Forecast methodology*

NT Gas has forecast its operations and maintenance expenditure for the access arrangement period using a base year approach. To derive this forecast, NT Gas has:

- identified an efficient base year and base year costs;
- adjusted for step changes including the removal from the base year of costs that are not indicative of future requirements and adding costs for new expenditures in future years not experienced in the past or embedded in the base year costs; and
- escalated costs for expected changes in input costs.

While there are limitations to using the base year approach, particularly as the scope of NT Gas operations for the pipeline has changed significantly in recent years, NT Gas considers that using the base year approach would provide the best estimate for routine operating expenditure for the pipeline. NT Gas also notes that significant adjustments would need to be made to whichever base year was chosen to adjust for the changing operation of the pipeline. These steps are discussed in the following sections.

All adjustments and step changes made to the operations and maintenance base year are discussed below, meaning that the materiality threshold used to determine forecast operating expenditure in this category is zero.<sup>87</sup>

#### *2009/10 base year*

NT Gas has used its 2009/10 actual expenditure in the operating and maintenance category as its base year for estimating operating and maintenance costs in the access arrangement period. NT Gas 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. Operating and maintenance expenditure in 2009/10 was \$7.28 million.

The 2009/10 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 NT Gas' operating expenditure in other years.

The first necessary adjustment to the base year relates to the abnormal level of work undertaken in that year on non-regulated assets. The commissioning of the Bonaparte Gas Pipeline occurred in this year with associated early gas arrangements, as well as the completion of the Weddell/Wickham Point Pipeline. These works undertaken by NT Gas on non-regulated pipelines meant that the proportion of fixed labour resources allocated to the AGP was significantly below

---

<sup>87</sup> AER's RIN requires NT Gas to specify the materiality threshold used to determine material forecast operating expenditure.



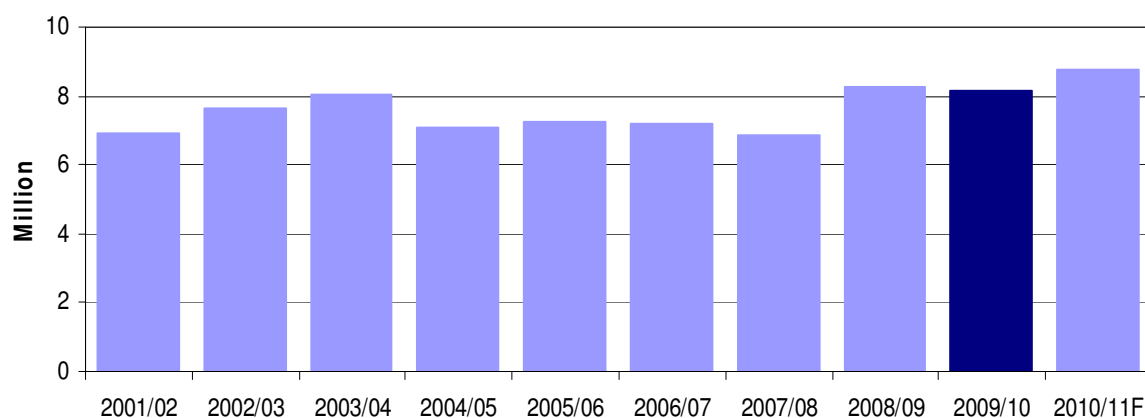
normal levels. The high level of non-AGP labour allocation is not expected to continue in the access arrangement period, as there are no major non-regulated works anticipated. It can therefore be expected that the full normal allocation of labour to the AGP will prevail in the access arrangement period.

The correction to the base year associated with abnormal labour allocations to non-regulated works leads to an increase in the base year costs as shown in confidential Attachment I, and summarised in Table 9.1 below, to take account of this incremental cost increase.

The second series of adjustments relates to expenditure in 2009/10 that is either non-routine, or which relates to projects that are not undertaken on an annual basis. NT Gas has removed non-routine expenditure associated with four operating expenditure projects from its base year as shown in confidential Attachment I, and summarised in Table 9.1 below.

The resulting base year operating and maintenance costs used for the purposes of forecasting expenditure in this category in the access arrangement period is \$8.13 million. This value is compared to actual (unadjusted) expenditure in the operating and maintenance category in the other years of the earlier access arrangement period in Figure 9.3 below.

**Figure 9.3 – Adjusted base year 2009/10 operating and maintenance expenditure compared to other years in the earlier access arrangement period**



### *Step changes*

A step change in operations and maintenance expenditure typically results from the introduction or removal of an obligation, or the adjustment of operations and maintenance programs or projects as the result of asset changes. Generally, a step change will result in a sustained departure from base year operations and maintenance expenditure, that is, a *step up* or *step down* in expenditure compared to the base year. In most cases, this is expected to be a permanent change and in some cases (such as pigging) it occurs periodically, but not on an annual basis. These step changes arise because a new regulatory obligation or a new operating activity is required to operate the network prudently and efficiently.



Step changes to the 2009/10 base year expenditure are discussed in the following sections.

#### Increased integrity works

As discussed above in relation to the enhanced integrity program (section 6.2.2), NT Gas has identified a number of integrity issues with the pipeline that it considers require immediate attention. In particular, DCVG surveys of the pipeline undertaken on a periodic basis have identified significant coating defects, with cracking of the factory installed polyethylene coating, which shields the pipeline from the CP system and causing corrosion.

The number of coating defects, and therefore dig-up repairs required to fix them, is significantly increased from those experienced in the earlier access arrangement period, and the number of digs undertaken in 2009/10. The 2009/10 base year expenditure includes 40 dig-ups and repairs, however NT Gas forecasts that it will undertake 100 dig-ups to repair coating defects in each year of the access arrangement period. NT Gas therefore forecasts a step change in the scope of integrity works, brought about by ageing of the pipeline, of 70 dig-ups a year.

This work is outsourced to suitably qualified contractors operating in the NT. Using the outsourced contractor rate currently applying, NT Gas has calculated a step change value to apply in each year of the access arrangement period as shown in confidential Attachment I, and summarised in Table 9.1 below, to take account of this incremental cost increase.

#### Changed requirements for Cathodic Protection surveys

NT Gas undertakes annual surveys of the CP system for the entire pipeline as required under the AGP licence. Inspections require the hire of a helicopter, which must be able to carry required personal and equipment to carry out the inspection along the length of the pipeline.

Changes in equipment requirements have meant that weight restrictions for the previous size helicopter are now breached, and NT Gas must procure a larger helicopter to undertake the surveys. This leads to increased costs that are required to ensure ongoing compliance with regulatory requirements, and which are beyond the control of NT Gas. Using the expected new contracted helicopter value, a step change representing the incremental cost difference between the previous and current helicopter hire rates is applied to each year of the access arrangement period as shown in confidential Attachment I, and summarised in Table 9.1 below, to take account of this incremental cost increase.

#### Access lease fees

NT Gas pays lease fees to indigenous land holders to access AGP easements. The existing agreement includes a trigger to renegotiate these fees in the event that the direction of flow on the pipeline changes. Forecast increases in this fee are applied to each year of the access arrangement period as shown in confidential Attachment I,



and summarised in Table 9.1 below, to take account of this incremental cost increase.

#### SCADA costs associated with asset changes

NT Gas has an ongoing contract with Honeywell Limited to provide and maintain its SCADA system. The addition of a new supply point to the AGP at Ban Ban Springs, as well as a new delivery and supply point at Weddell, has changed the scope of NT Gas' operations, and led to increased data points added to the SCADA system, and associated support and maintenance costs under the existing contract.

NT Gas has included a step change applied to each year of the access arrangement period as shown in confidential Attachment I, and summarised in Table 9.1 below, to take account of this incremental cost increase.

#### Replacement of emergency response trucks

As noted in section 6.2.2 in relation to replacement capital expenditure in the earlier access arrangement period, NT Gas had previously forecast the replacement of two emergency response trucks in 2007. NT Gas was able to prudently defer this expenditure in the earlier access arrangement period after inspection of the trucks showed that their condition was still good and they were suitable for continued service.

NT Gas forecasts that it will replace the emergency response trucks in 2011/12, as these trucks will be 16 years old at this stage, and four years past the scheduled replacement date. In line with NT Gas' practice in relation to vehicles, NT Gas will lease the vehicles over four years, with a residual lease payment in 2014/15. Average lease payment amounts have been added to the base year costs in the years in which they are forecast to be incurred, starting in 2011/12. The value of this step change is shown in confidential Attachment I, and summarised in Table 9.1 below.

#### Non-annual expenditure

NT Gas has identified a number of step changes that need to be applied to particular years in the access arrangement period as follows:

- Right of way erosion;
- Intelligent pigging;
- Above ground station recoating; and
- Battery replacement.

These are discussed below.

NT Gas must maintain easements associated with the AGP and keep them in good condition, including addressing any erosion occurring on easements as they are



generally kept clear of significant vegetation. Weather conditions have a significant impact on erosion on these sites, in particular extended periods of high rainfall.

NT Gas forecasts that it will incur increased right of way costs in 2010/11 and the first two years of the access arrangement period associated with erosion arising from the current high rainfall in NT, largely arising from the La Niña event affecting the east and north coasts of Australia. These increased costs are not reflected in the 2009/10 base year, which was near the end of a relatively dry spell of weather. Historically, NT Gas' right of way costs increase in the years following rainfall events.

NT Gas therefore proposes a step change in costs associated with the current high rainfall in 2011/12 and 2012/13, calculated as an increment on 'normal' right of way expenditure incurred in 2009/10. The value of the step change is shown in confidential Attachment I, and summarised in Table 9.1 below.

NT Gas undertakes periodic intelligent pigging of the AGP to identify corrosion or deformities of the pipeline. NT Gas has previously adopted a ten year schedule for pigging the entire pipeline (undertaken by section on a rotating schedule), but has recently moved to a seven year pigging cycle to adequately monitor and manage corrosion under shrink sleeves. Further details on the pigging schedule for the pipeline are included in the Asset Management Plan.

According to this schedule, NT Gas will pig the Mataranka to Darwin section of the pipeline in 2012/13, and the Mataranka to Palm Valley section in 2015/16. Forecast costs for these activities are shown in confidential Attachment I, and summarised in Table 9.1 below.

Above ground assets at meter stations are continuously exposed to the elements. These assets are painted to deter corrosion, but this paint must be periodically sandblasted and repainted to maintain protection. NT Gas schedules to recoat a meter station every second year of the access arrangement period, starting 2011/12. Forecast costs for this activity are shown in confidential Attachment I, and summarised in Table 9.1 below.

Ongoing periodic maintenance of meter station sites is required, and forecast operating expenditure includes replacement of site batteries at solar sites as non-routine expenditure in the access arrangement period. This expenditure is not included in the base year numbers. Forecast costs for this activity are shown in confidential Attachment I, and summarised in Table 9.1 below.

**Table 9.1 – Summary table of base year adjustments and step changes**

| Adjustment/step change                        | Value ('000 \$2009/10) |
|---|------------------------|
| Unadjusted operations & maintenance base year | 7,282                  |
| Adjustments to base year                      | 846                    |
| Adjusted operations & maintenance base year   | 8,128                  |
| Step changes to base year                     | 272                    |
| <b>Base year after annual step changes</b>    | <b>8,400</b>           |





### *Escalation*

The base year (2009/10) has been broken down into two input cost categories for the purposes of escalation: Labour and Other. Each step change has also been broken down into these categories.

Base year cost splits were derived from actual expenditure, and these splits were applied to forecast expenditure in the same ratio. The split for each step change has been derived either from historical information (where the step change related to non-routine work not already included in the base year), or by analysis of the specific components of forecast costs (where historic information cannot be used).

NT Gas applied the same escalation rates to operating and maintenance expenditure as it applied in relation to capital expenditure (an annual real increase in labour costs of 1.5 per cent per annum), and the method for deriving this rate is discussed above in section 6.3.2.

### *Forecast operations and maintenance expenditure*

NT Gas' forecast operations and maintenance expenditure for the access arrangement period is shown in Table 9.2 below.

**Table 9.2 – Total forecast operations and maintenance expenditure in the access arrangement period**

| \$ '000 (2009/10)        | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | Total  |
|--------------------------|---------|---------|---------|---------|---------|--------|
| Operations & maintenance | 8,750   | 10,391  | 8,924   | 8,985   | 11,019  | 48,069 |

NT Gas considers that its forecast for operations and maintenance expenditure has been arrived at on a reasonable basis and represents the best forecast or estimate possible in the circumstances, as required under Rule 74. Forecast operations and maintenance expenditure is required to ensure ongoing compliance with regulatory obligations, and has been determined using the planning and asset management processes and procedures set out in chapter 4 above.

## 9.3.2 Overheads expenditure

### *Forecast methodology*

NT Gas has forecast its overheads expenditure using a combination of base year and zero base approaches, reflecting the nature of components that make up this operating expenditure category. Overheads expenditure in the earlier access arrangement period can be split into:

- Local overheads – administration and management costs incurred in local operations;





- Corporate overheads – allocation of group-level costs associated with service provided to NT Gas by APA group, such as legal, regulatory, training and group human resources functions;
- Insurance costs; and
- Regulatory costs – costs associated with the periodic review of the access arrangement applying to the pipeline.

NT Gas has forecast its local overheads using the base year methodology, selecting 2009/10 as the appropriate base year from which to derive its forecast. Methodological steps necessary to adjust the base year are identical to those described above in relation to operations and maintenance expenditure, and are only discussed in relation to their application to local overheads costs below.

Corporate overheads, insurance and non-controllable costs have been forecast using a zero base method, based on known allocations and costs.

All adjustments and step changes made to the overheads category are discussed below, meaning that the materiality threshold used to determine forecast operating expenditure in this category is zero.<sup>88</sup>

### *Components of forecast*

#### Local overheads

NT Gas has used its 2009/10 actual expenditure as its base year for estimating local overheads costs in the access arrangement period. Just as for operations and maintenance expenditure, NT Gas 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. Local administrative costs in 2009/10 were \$0.8 million.

Upon analysis of the underlying expenditure in this category, NT Gas does not consider that any adjustments or step changes are required before these costs can be used as a basis for forecast expenditure.

Forecast costs for this component of forecast overheads expenditure are shown in Table 9.3 below.

#### Corporate costs

Rule 93 requires the Service Provider to design Reference Tariffs to collect revenues equal the costs of providing the Reference Service, where the cost of providing the Reference Service is derived through a reasonable allocation of costs. This requires a reasonable allocation of shared costs, including corporate costs and owner's costs.

---

<sup>88</sup> NT Gas' RIN requires NT Gas to specify the materiality threshold used to determine material forecast operating expenditure.



In instances such as the AGP, where the owners and operators of the pipeline also own and/or operate other assets, the joint and shared costs incurred need to be allocated between all assets in a reasonable manner.

This section outlines the budgeting and corporate governance process surrounding the development of the corporate costs forecast.

- APA Corporate Cost budget

APA corporate costs are subject to a comprehensive planning and review process. The APA Board approved budget represents a reasonable basis for estimating the future corporate costs of the APA Group. Note that these costs do not include insurance costs or the costs of any future mergers, acquisitions, divestments or similar corporate projects.

The total corporate cost is built up from the costs of various corporate functions. These functions are:

- Chief Executive Officer function;
- Company Secretary function – including annual reporting, general meetings, risk management, compliance management, directors costs and general administrative costs;
- Corporate Finance function – including, treasury, tax, budgeting, general financial and management accounting;
- Corporate Commercial function – including corporate legal, investor relations, strategic planning and general commercial functions;
- Operations – including general oversight of the operations functions of all assets;
- Human Resources – including health safety and environment, employee communications, payroll, recruiting;
- Financial Services Centre (e.g., accounts payable processing);
- IT; and
- Technical services – including asset management, engineering services and project management.

Note that regulatory costs are excluded from the commercial costs.

- APA Corporate Cost Forecasts

The costs for the functions above are then projected forward by financial years to 2015/16 based on known and reasonably expected corporate projects.



These costs include operating costs for current separate Information Technology (IT) and finance transformation projects in the earlier years which reduce in the later years. These projects involve consolidation and rationalisation of IT and finance applications across the APA group to allow greater efficiencies moving forward. For example, APA currently has three separate major finance systems, three works management systems, four Geographic Information Systems (GISs), four incident management systems and four intranets in use. APA is currently rationalising and replacing IT systems, processes and applications, including systems and applications used to support the AGP.

The costs of updating and integrating business processes and systems are not insubstantial. By recognising these costs the AER is then in a position to potentially recognise subsequent efficiencies. Such efficiencies will only start to be realised following the completion of the project.

While synergies are expected to result in time, at this stage it is impossible to accurately quantify these synergies. Given this, the synergies resulting from the project should first be realised and quantified and then, via the application of the efficiency benefit sharing mechanism inherent in the “revealed cost” approach to operating expenditure forecasting, be returned in future access arrangement periods.

- Allocation of APA Corporate Costs to AGP

Thirdly, these costs are then allocated to individual operating pipelines, including the AGP. The allocation process:

- assigns any directly attributable costs to the relevant asset;
- allocates costs to assets based on causal allocators where possible; and
- allocates remaining costs based on APA's individual assets' budgeted revenues.

APA Group has assigned its corporate costs across its operating assets consistently over time and over a number of access arrangement revision filings. In previous regulatory processes this revenue based methodology of allocating costs has been accepted by the ACCC/AER.

In 2010/11 APA Group's budgeted revenue is \$689.3 million and the AGP is budgeted to earn \$29.0 million. Thus the general allocator is 4.2 per cent.

Following this the APA Group corporate costs attributable to the AGP Group have been derived and are shown in Table 9.3 below.

#### Regulatory submissions

NT Gas has included expected costs for completing a regulatory submission in accordance with its obligations under its revised access arrangement. The adjustment is in 2015/16 and aligns with the proposed revision submission date in the revised access arrangement.



The 2009/10 base year costs for local overheads do not include any expenditure associated with the current access arrangement revision proposal. In addition, general corporate overhead costs do not include project specific costs of this kind, which are allocated directly to the business on project by project basis. Therefore it is appropriate to include costs in the access arrangement period for this periodic regulatory obligation, in accordance with the revenue and pricing principles that state 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.<sup>89</sup>

Forecast costs for this component of forecast overheads expenditure are shown in Table 9.3 below.

### *Escalation*

There is no labour component in the local overhead or insurance sub-categories so no escalation has been applied to these categories.

The corporate overheads and regulatory costs sub-categories have been escalated in full by NT Gas' proposed labour escalator, reflecting the nature of predominant costs in that category.

NT Gas applied the same escalation rates to overheads expenditure as it applied in relation to capital expenditure (an annual real increase in labour costs of 1.5 per cent per annum), and the method for deriving this rate is discussed above in section 6.3.2.

### *Forecast overheads costs*

Total forecast costs in the overheads category are shown in Table 9.3 below. NT Gas considers that it has derived this forecast on a reasonable basis, and considers that it represents the best forecast or estimate possible in the circumstances.

NT Gas further considers that its forecast expenditure is consistent with expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

Forecasts have been derived using known historical costs and rates of growth, and allocated to NT Gas' regulated activities using the same allocation methodology as used to derive forecasts and record costs in the earlier access arrangement period.

---

<sup>89</sup> National Gas Law, section 24



**Table 9.3 – Total forecast overheads expenditure in the access arrangement period**

| \$ '000 (2009/10)     | 2011/12      | 2012/13      | 2013/14      | 2014/15      | 2015/16      | Total         |
|-----------------------|--------------|--------------|--------------|--------------|--------------|---------------|
| Local overheads       | 805          | 805          | 805          | 805          | 805          | <b>4,025</b>  |
| Corporate overheads   | 2,163        | 2,224        | 2,257        | 2,291        | 2,326        | <b>11,261</b> |
| Insurance             | 1,261        | 1,261        | 1,261        | 1,261        | 1,261        | <b>6,304</b>  |
| Regulatory submission | 0            | 0            | 0            | 0            | 646          | <b>646</b>    |
| <b>Total</b>          | <b>4,229</b> | <b>4,290</b> | <b>4,323</b> | <b>4,357</b> | <b>5,038</b> | <b>22,237</b> |

### 9.3.3 Sales and marketing expenditure

#### *Forecast methodology*

NT Gas does not consider that the base year methodology is a suitable methodology to derive its forecast sales and marketing expenditure. This is because actual expenditure in the earlier access arrangement period, including expenditure in 2009/10, is highly atypical of expenditure to be expected in the access arrangement period due to the recent emergence of available gas and capacity on the pipeline.

NT Gas has therefore derived its forecast in line with the forecast in the earlier access arrangement period. No escalation applies to sales and marketing expenditure as it has no labour component.

#### *Sales and marketing expenditure forecast*

NT Gas' sales and marketing expenditure forecast is shown in Table 9.4 below. NT Gas considers that this forecast is conservative, as it reflects the base level of sales and marketing expenditure experienced prior to the earlier access arrangement period (the value on which the previous forecast was based), and does not include an increase in expenditure associated with the increased capacity of the pipeline brought about by the connection of the Bonaparte Gas pipeline.

It could be expected that sales and marketing expenditure would increase significantly with the availability of gas supply and the potential for interruptible and potential firm contracts on the pipeline using unutilised contracted capacity.<sup>90</sup> NT Gas has, however, forecast a return to 'normal' levels of expenditure in this class, without factoring in these changes in gas availability that would tend to drive up expenditure, as it is difficult to forecast the impact of these factors with the level of certainty required to underpin the forecast. NT Gas therefore considers that its forecast is the best possible in the circumstances, as it is based on its historic 'normal' expenditure in this category.

<sup>90</sup> While PWC sought alternative gas supplies to replace depleting supplies from the Amadeus Basin, there is some gas available for sale from this Basin, albeit not at the volumes required by PWC.



**Table 9.4 – Total forecast sales and marketing expenditure in the access arrangement period**

| \$ '000 (2009/10) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | Total |
|-------------------|---------|---------|---------|---------|---------|-------|
| Sales & marketing | 172     | 172     | 172     | 172     | 172     | 860   |

### 9.3.4 Total forecast operating expenditure

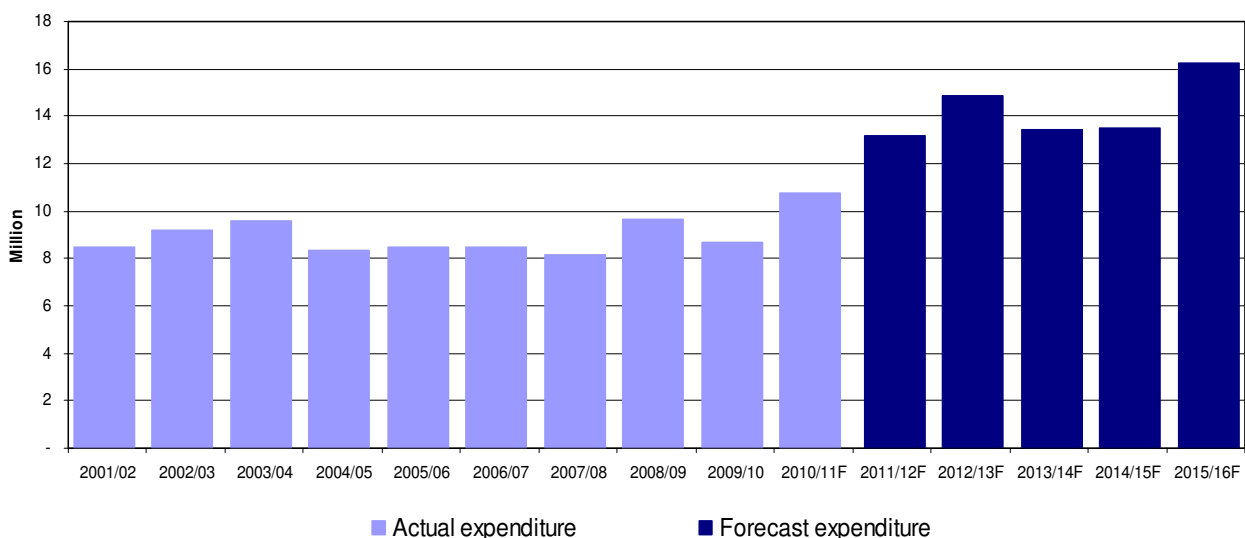
Forecast operating expenditure over the access arrangement period is shown in Table 9.5 below.

**Table 9.5 – Forecast operating expenditure over the access arrangement**

| \$ '000 (2009/10)        | 2011/12       | 2012/13       | 2013/14       | 2014/15       | 2015/16       | Total         |
|--------------------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Operations & maintenance | 8,750         | 10,391        | 8,924         | 8,985         | 11,019        | 48,069        |
| Overheads                | 4,229         | 4,290         | 4,323         | 4,357         | 5,038         | 22,237        |
| Sales & marketing        | 172           | 172           | 172           | 172           | 172           | 860           |
| <b>Total</b>             | <b>13,152</b> | <b>14,853</b> | <b>13,419</b> | <b>13,514</b> | <b>16,229</b> | <b>71,165</b> |

Operating expenditure for the access arrangement period compared to the earlier access arrangement period is shown in Figure 9.4 below.

**Figure 9.4 – Operating expenditure over the earlier access arrangement period and access arrangement period**



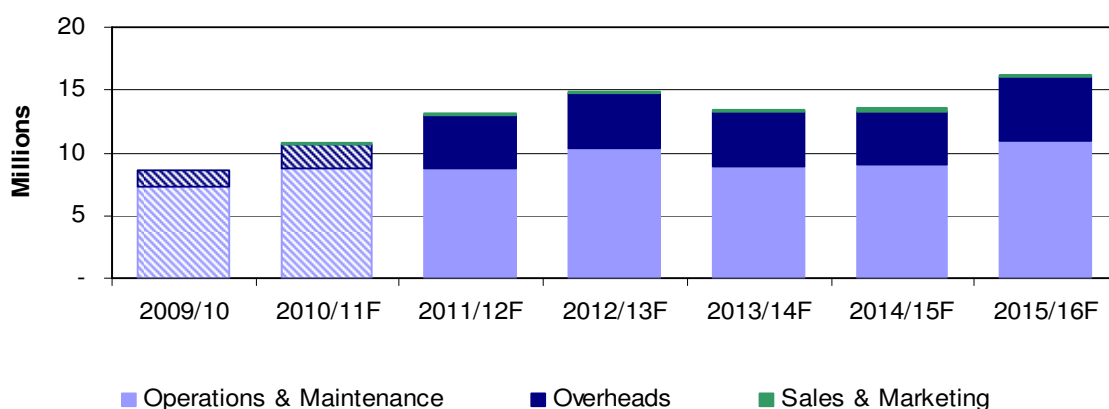
As can be seen from the graph, there is an increase in operating expenditure over the access arrangement period compared to the earlier period.

Forecast operating expenditure by category is shown in Figure 9.5 below, compared with expenditure in the last two years of the earlier access arrangement period



(shown with diagonal stripes). As can be seen from the graph, the main driver of the increase in operating expenditure is the change in the overheads category, with a contribution from the operations and maintenance category. The drivers for these changes, as well as the basis for the forecast, are discussed above for each of these categories.

**Figure 9.5 – Forecast operating expenditure by category over the access arrangement period**



NT Gas considers that its forecast operating expenditure for the access arrangement period satisfies the requirements under Rule 91 that it be expenditure that would be incurred by a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve the lowest sustainable cost of providing services.

Forecasts have been arrived at on a reasonable basis, using the best available information applying to the business and the pipeline. NT Gas operating expenditure also compares well with that of comparable service providers, as shown in the following sections.

## 9.4 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.

### 9.4.1 Issues on performance measures and benchmarking of transmission pipelines

#### *Differences in pipeline characteristics*

It is important to recognise the limitations of benchmarking. The numerous variables that can and do affect costs means that benchmarking can only provide a broad



indication of whether a particular pipeline's costs lie within the range of possible efficient costs.

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

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

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

- Some operating expenditure items such as vegetation management and easement surveys are significantly driven by both the length of the pipeline route and the nature of the environment through which the pipeline runs. The pipeline route of the AGP is one of the longest in the nation, resulting in an increased level of easement management and maintenance, compared to other, shorter pipelines;
- Some operating expenditure items such as internal inspections (intelligent pigging) and cathodic protection surveys are driven by the actual length of the pipe. In the case of the AGP, the relevant length for such costs is close to the entire 1,629 kilometres of the pipeline; and
- The AGP's remote location, requiring fly-in/fly-out and remote accommodation arrangements, additional personnel costs arising from relevant award conditions, and complexity of contractual arrangements for pipeline services.

### *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 (although even this must be adjusted to reflect the age of the pipeline in question). As a proxy for replacement costs, AGP 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
- \$ cost per mmkm of pipeline diameter x length

The costs benchmarked below reference 2009/10 operating expenditure for the AGP reported in Table 9.6 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<sup>91</sup>
- Moomba-Adelaide Pipeline
- Dampier-Bunbury Natural Gas Pipeline
- Roma-Brisbane Pipeline
- Moomba Sydney Pipeline
- Goldfields 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.

## 9.4.2 Key findings

AGP's costs are amongst the lowest of the benchmarked businesses.

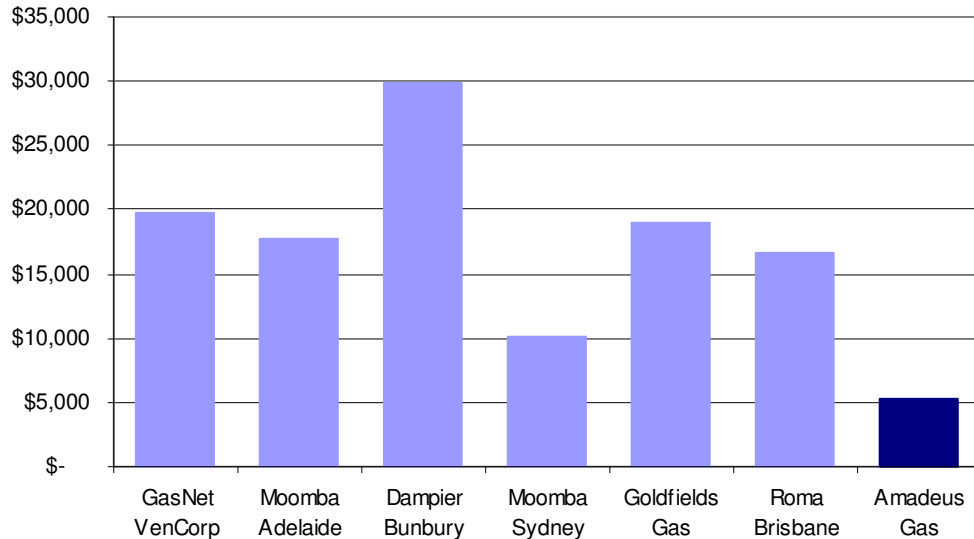
### *Operating expenditure cost per km*

For operating expenditure per kilometre of pipeline route the AGP's performance is lower than comparator pipelines.

---

<sup>91</sup> While the GasNet system is now operated by AEMO, the current access arrangement determination was put in place when the GasNet system was operated by VENCorp.

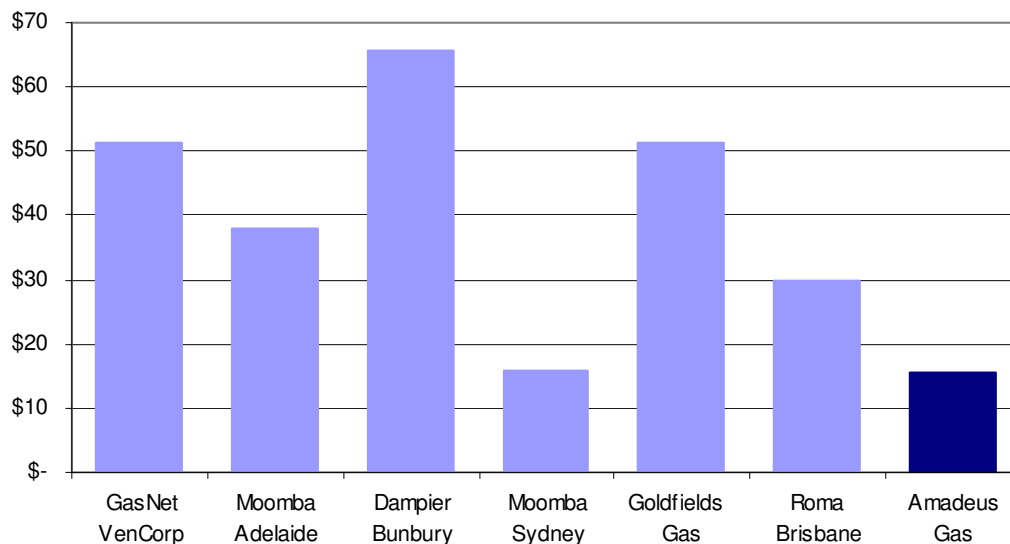
**Figure 9.6 – Operating expenditure per kilometre**



*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 AGP performs in line with other Australian pipelines.

**Figure 9.7 – Operating expenditure per mmkm**



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



### 9.4.3 Forecast operating expenditure and demand and utilisation forecasts

In general, demand forecasts have only limited impact on operating expenditure, except where increases in demand lead to new capital expenditure that requires additional operating and maintenance resources. As noted in chapter 6 above in relation to expansion capital expenditure, NT Gas does not forecast any additional expenditure associated with network expansion, and therefore the demand forecasts set out in 5.2 do not drive NT Gas' operating expenditure forecasts.

Sales and marketing expenditure has, however, been influenced by capacity and utilisation of the pipeline over the earlier access arrangement period (along with the availability of gas), and forecast capacity and utilisation is relevant to NT Gas' forecast sales and marketing expenditure. As discussed above, the availability of capacity on the pipeline has led NT Gas to assume that its marketing expenditure will return to normal levels over the access arrangement period.

## 9.5 Outsourced expenditure

The AER RIN requires NT Gas to submit certain information related to outsourced forecast operating expenditure that contributes in a material way to the provision of pipeline services.

NT Gas has identified one outsourced contract in place contributing to forecast operating expenditure in relation to telecommunication services. Further information on this contract is provided in confidential Attachment F. There are also some ongoing relationships with external providers that NT Gas expects will continue in the access arrangement period. These are also outlined in Attachment F.



**Table 9.6 – Comparison of ACCC 2002 Final Decision and actual and forecast operating expenditure over the earlier access arrangement period**

| \$ '000 (2009/10)   | 2001/02      | 2002/03      | 2003/04       | 2004/05        | 2005/06      | 2006/07        | 2007/08      | 2008/09      | 2009/10      | 2010/11F      | Total          |
|---|--------------|--------------|---------------|----------------|--------------|----------------|--------------|--------------|--------------|---------------|----------------|
| <b>ACCC 2002 Final Decision</b>   |              |              |               |                |              |                |              |              |              |               |                |
| Operations & Maintenance  | 6,688        | 6,874        | 8,549         | 7,693          | 7,456        | 8,314          | 7,274        | 8,187        | 7,418        | 7,710         | 76,163         |
| Overheads   | 1,690        | 1,684        | 1,682         | 1,680          | 1,654        | 1,659          | 1,625        | 1,639        | 1,628        | 1,667         | 16,608         |
| Sales & Marketing   | 172          | 172          | 172           | 172            | 170          | 170            | 167          | 169          | 168          | 172           | 1,705          |
| <b>Total forecast</b>   | <b>8,550</b> | <b>8,731</b> | <b>10,403</b> | <b>9,545</b>   | <b>9,280</b> | <b>10,143</b>  | <b>9,066</b> | <b>9,995</b> | <b>9,214</b> | <b>9,549</b>  | <b>94,475</b>  |
| <b>Actual and forecast capital expenditure</b>  |              |              |               |                |              |                |              |              |              |               |                |
| Operations & Maintenance  | 6,892        | 7,658        | 8,038         | 7,058          | 7,231        | 7,195          | 6,846        | 8,240        | 7,282        | 8,776         | 75,216         |
| Overheads   | 1,317        | 1,411        | 1,473         | 1,161          | 1,183        | 1,205          | 1,239        | 1,378        | 1,318        | 1,918         | 13,602         |
| Sales & Marketing   | 237          | 127          | 71            | 108            | 54           | 46             | 47           | 37           | 59           | 59            | 845            |
| <b>Total actual</b>   | <b>8,446</b> | <b>9,196</b> | <b>9,582</b>  | <b>8,326</b>   | <b>8,468</b> | <b>8,446</b>   | <b>8,132</b> | <b>9,656</b> | <b>8,660</b> | <b>10,753</b> | <b>89,664</b>  |
| <b>Variance between ACCC 2002 Final Decision and NT Gas actual and forecast capital expenditure</b> |              |              |               |                |              |                |              |              |              |               |                |
| Operations & Maintenance  | 204          | 784          | (512)         | (636)          | (225)        | (1,119)        | (427)        | 54           | (135)        | 1,066         | (946)          |
| Overheads   | (373)        | (274)        | (209)         | (519)          | (471)        | (453)          | (386)        | (261)        | (310)        | 251           | (3,005)        |
| Sales & Marketing   | 65           | (45)         | (101)         | (65)           | (116)        | (124)          | (120)        | (131)        | (108)        | (113)         | (860)          |
| <b>Total variance</b>   | <b>(104)</b> | <b>465</b>   | <b>(822)</b>  | <b>(1,220)</b> | <b>(811)</b> | <b>(1,697)</b> | <b>(934)</b> | <b>(339)</b> | <b>(554)</b> | <b>1,204</b>  | <b>(4,811)</b> |



## 10 Total revenue

Rule 76 requires the total revenue to be derived according to a building block approach. The considerations relevant to each of the building blocks are discussed in the relevant sections above. This section summarises those building blocks to present the total revenue requirement.

### 10.1 Return on capital

The required return on the capital base is discussed in chapter 8. The required return on the capital base is summarised in Table 10.1 below.

**Table 10.1 – Return on capital**

| \$ '000 (nominal) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|-------------------|---------|---------|---------|---------|---------|
| Return on capital | 12,841  | 13,384  | 13,138  | 12,869  | 12,527  |

### 10.2 Regulatory depreciation

The forecast straight line depreciation over the access arrangement period is discussed in section 7.2.3. To calculate the amount of regulatory depreciation applicable to the revenue requirement, the amount of indexation of the capital base must be subtracted from the straight line depreciation. The indexation of the capital base is discussed in section 7.2.5.

Together, these two amounts combine to derive the forecast regulatory depreciation as shown in Table 10.2.

**Table 10.2 – Forecast depreciation over the access arrangement period**

| \$ '000 (nominal)          | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|----------------------------|---------|---------|---------|---------|---------|
| Straight line depreciation | 7,369   | 6,743   | 6,967   | 7,205   | 3,710   |
| Indexation                 | 2,811   | 2,930   | 2,876   | 2,817   | 2,742   |
| Regulatory depreciation    | 4,558   | 3,814   | 4,091   | 4,388   | 968     |

### 10.3 Corporate income tax

As discussed above in the context of establishing the TAB, the Rules do not mandate a particular approach for dealing with taxation in the access arrangement. Rather, Rule 72(1)(h) requires the service provider to indicate the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated.



For the purposes of this access arrangement, NT Gas has adopted a post tax approach. Under this approach, the cash flows of the business include an estimate of the amount of tax payable on regulatory revenues.

**Table 10.3 – Corporate income tax allowance**

| \$ '000 (nominal) | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|-------------------|---------|---------|---------|---------|---------|
| Tax allowance     | 1,874   | 1,755   | 1,996   | 2,023   | 874     |

## 10.4 Revenue requirement

### 10.4.1 Total revenue requirement

Combining these components as required under Rule 76 derives a total revenue requirement as shown in Table 10.4 below.

**Table 10.4 – Total revenue requirement**

| \$ '000 (nominal)       | 2011/12       | 2012/13       | 2013/14       | 2014/15       | 2015/16       |
|-------------------------|---------------|---------------|---------------|---------------|---------------|
| Return on capital       | 12,841        | 13,384        | 13,138        | 12,869        | 12,527        |
| Regulatory Depreciation | 4,558         | 3,814         | 4,091         | 4,388         | 968           |
| Operating expenditure   | 13,817        | 15,995        | 14,812        | 15,290        | 18,820        |
| Tax Allowance           | 1,874         | 1,755         | 1,996         | 2,023         | 874           |
| Revenue requirement     | <b>33,090</b> | <b>34,948</b> | <b>34,036</b> | <b>34,570</b> | <b>33,189</b> |

The present value of this revenue requirement stream, discounted at the WACC of 11.42%, is \$124.21 million.

## 10.5 Incentive mechanisms

There were no incentive mechanisms in the earlier access arrangement period that have ongoing application or administrative requirements in the access arrangement period.

Looking forward, the National Gas Access Regime, defined by the NGL and Rules, focuses on reference tariffs and is therefore fundamentally a “price cap” regime.

Under a price cap regime, the service provider has clear incentives to:

- reduce operating expenditure from approved forecast levels;
- defer or avoid capital expenditure relative to the approved forecast; and
- increase the utilisation of the pipeline.



Under the AER's 'revealed cost' approach, the benefits of these actions are retained by the business until the next regulatory reset, at which time they form the foundations of cost and revenue forecasts for the following access arrangement period. The benefits arising from these activities are therefore delivered to Users in the access arrangement period following that in which the activities are undertaken.

Beyond the incentives encapsulated in the Rules, NT Gas does not propose any incentive mechanism for the AGP.







# 11 Tariffs

This chapter explains the basis and derivation of pipeline tariffs, including the allocation of total revenue and costs to pipeline services and the reference tariff variation mechanism.

## 11.1 Revenue allocation

### 11.1.1 Revenue requirement

The total revenue requirement derived from the building block approach is shown in Table 11.1 below.

**Table 11.1 – Forecast revenue requirement over the access arrangement period**

| \$ '000 (nominal)                      | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|--|---------|---------|---------|---------|---------|
| AGP Building block revenue requirement | 33,090  | 34,948  | 34,036  | 34,570  | 33,189  |

The present value of this revenue requirement, discounted at the WACC of 11.42 per cent, is \$124.21 million.

### 11.1.2 Revenue and cost allocation to services

Rule 93(2) requires costs to be allocated between reference and other services as follows:

- (a) Costs directly attributable to reference services are to be allocated to those services;
- (b) Costs directly attributable to pipeline services that are not reference services are to be allocated to those services;
- (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.

Revenue is to be allocated between reference and other services in the same ratio in which costs are allocated between reference and other services.<sup>92</sup>

NT Gas proposed three pipeline services, one of which is also a reference service. NT Gas must therefore allocate costs between these services based on the costs directly attributed to those services.

---

<sup>92</sup> Rule 93(1)



As set out in the chapter 5 above, there is currently only one user of the pipeline. This user takes a firm transportation service akin to the proposed reference service, and is currently contracted for the full capacity of the pipeline.

In the earlier access arrangement period, there were limited contracts in place for non-reference services, which accounted for less than one per cent of total gas volumes over the period. This is largely because the firm reference service was fully contracted. There are currently no contracts in place for the pipeline on terms other than those comparable to the reference service (that is, other than the foundation contract with PWC).

To the extent that there may be contracted but unutilised capacity on the pipeline during the access arrangement period, NT Gas may be able to offer the reference service to additional users.<sup>93</sup> NT Gas expects prospective users to preferentially choose the firm reference service over other pipeline services (in line with its experience in the earlier access arrangement period where prospective users preferentially sought a firm service). As a result, NT Gas does not forecast any demand for the interruptible or negotiated service during the access arrangement period. In any case, NT Gas could not provide a reasonable estimate of what demand may be for these services as there are currently no contracts for these services in place, nor is NT Gas in any negotiations for these services.

As there are no current users of non-reference services, NT Gas does not currently incur costs for the AGP associated with providing non-reference services. Similarly, NT Gas does not forecast any users of non-reference services, and therefore does not forecast any costs to be allocated to these services. As a result, NT Gas has allocated all costs and revenue to be recovered through the reference service.

## 11.2 Reference Tariff

### 11.2.1 Rules requirements

Rule 95(1) requires that a tariff for a reference service be developed:

- (a) To generate from the provision of each reference service the portion of total revenue referable to that reference service; and
- (b) As far as reasonably practicable consistently with paragraph (a), to generate from the user, or the class of users, to which the reference service is provided, the portion of total revenue referable to providing the reference service to the particular user or class of users.

As NT Gas only proposes to offer one reference service, Rule 92(2), which relates to the allocation of revenue between reference services, does not apply.

---

<sup>93</sup> As discussed in section 5.2.4, NT Gas does not forecast any additional users of the AGP (that is, users other than PWC) over the access arrangement period as it currently has no basis on which to forecast the location or demand of any prospective users.



Rule 95(2) requires that the portion of total revenue referable to providing a reference service to a particular user or class of users is determined as follows:

- (a) costs directly attributable to supplying the user or class of users are to be allocated to the relevant user or class; and
- (b) other costs are to be allocated between the user or class of users and other users or classes of users on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the AER.

This is a limited discretion Rule.

### 11.2.2 Allocation to user classes

As outlined above, NT Gas has allocated all revenue associated with the AGP to the reference service. Further, NT Gas forecasts only one user of a service akin to the reference service, and has therefore allocated all relevant costs and revenue associated with that user to the reference service.

The reference tariff proposed is a simple capacity tariff based on firm Maximum Daily Quantities (MDQs) at each delivery point. This tariff allows NT Gas to recover its revenue requirement from users of the pipeline in proportion to their capacity requirements, which matches the reference service which is a bidirectional service from between any receipt and delivery point.

NT Gas has identified a single class of user of the pipeline in line with the fact that there is only one user of the pipeline contracting its capacity through a single transportation agreement. It can be expected that any potential additional users of the pipeline will also be in the same class as the principal user of the reference service as those users are not expected to give rise to specific costs (or avoid any specific costs) compared to the principal user of the reference service.

As a result, revenue associated with providing the reference service has been allocated to a single user class consistent with the requirement that direct and other costs associated with providing the reference service are allocated in accordance with the cost of providing the reference service to that class of user.

### 11.2.3 Revenue equalisation and X-factors

The revenue requirement as outlined in section 10.4.1 above varies by year according to differing operating and other requirements over the course of the access arrangement period. In order to present a smooth price path, Rule 92(2) requires a smoothed revenue path to be derived, in present value terms.

Applying the WACC of 11.42 per cent the smoothed revenue requirement that would derive the same net present value of cash flows is outlined in Table 11.2 below.



**Table 11.2 – Smoothed revenue requirement**

| \$ '000 (nominal)            | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16F |
|------------------------------|---------|---------|---------|---------|----------|
| Smoothed Revenue requirement | 32,481  | 33,293  | 34,125  | 34,978  | 35,853   |

The revenue path is then translated, reflecting changes in demand requirements, into a price path in a CPI-X format. This derives the unit price to apply in each year of the access arrangement period based on a defined starting point. The 2011/12 tariff that forms the starting point for the access arrangement period is \$0.76/GJ.

As the structure of the tariff has changed from the earlier access arrangement, there is no  $P_0$  ("P-nought") X factor to be applied to prices in effect in 2010/11. Rather, the access arrangement provides the price per unit of demand for 2011/12 and X factor information for future years as shown in Table 11.3 below. The zero X factors in the later years of the access arrangement period translate into zero real price changes over the period.

**Table 11.3 – X Factors**

|           | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
|-----------|---------|---------|---------|---------|---------|
| X Factors | N/A     | 0       | 0       | 0       | 0       |

## 11.3 Reference tariff variation

NT Gas proposes to revise its reference tariff variation mechanism included in the earlier 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. NT Gas has included two reference tariff variation mechanisms in its access arrangement:

- an annual reference tariff adjustment formula mechanism – to apply on 1 July 2012 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 NT Gas may seek to vary the reference tariff as a result of a cost pass-through event.

This is similar to the earlier access arrangement where the reference tariff was adjusted by CPI and by uncontrollable costs, referred to as *imposts*.



In deciding whether a particular reference tariff variation mechanism is appropriate, the AER must have regard to:<sup>94</sup>

- 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 earlier access arrangement; and
- the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

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

### 11.3.1 Annual reference tariff adjustment formula mechanism

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

NT Gas' earlier access arrangement included an annual tariff variation formula in its tariff variation mechanism to vary all prices by CPI, an X factor, and a Y factor. NT Gas proposes to retain an annual tariff variation formula that adjusts the reference tariff by CPI and by an X factor. The X factor smooths required tariff increases over the access arrangement period. NT Gas' proposed X factors are discussed in section 11.2.3 above.

NT Gas 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<sup>95</sup>;
- is readily verifiable by external parties, including users and prospective users, thereby reducing compliance costs<sup>96</sup>;
- is consistent with the previous NT Gas access arrangement, in providing for the annual adjustment of the reference tariff in accordance with movements in CPI<sup>97</sup>; and
- is consistent with recent AER decisions for access arrangements applying to similar services, for example in relation to the Jemena Gas Networks NSW gas distribution networks<sup>98</sup>.

---

<sup>94</sup> Rule 97(3)

<sup>95</sup> Rule 97(3)(a)

<sup>96</sup> Rule 97(3)(b)

<sup>97</sup> Rule 97(3)(c)



### 11.3.2 Cost pass-through reference tariff variation mechanism

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

NT Gas has not included specific defined cost pass-through events in the access arrangement. It has instead elected to define cost pass-through events in general terms as those events that are uncontrollable, and that are unforeseen or not able to be accurately forecast at the time the access arrangement is approved, that lead to or are expected to lead to material changes in costs that are not already included in the reference tariff, that would otherwise be appropriately included in reference tariffs if they were known or forecastable at the time the access arrangement was approved. NT Gas considers that this approach reflects the practicalities of cost pass-through events in that they are usually unforeseen, as well as recent regulatory practice by the AER.

Drafting multiple cost pass-through event definitions to capture a broad range of possible outcomes risks not allowing the recovery of costs associated with an otherwise legitimate event due to the limitations of foresight, as recognised by the AER in respect of the ACT 2009-14 electricity distribution determination:

Unforeseeable events are not easily defined. Therefore, rather than attempting to specifically define all unforeseeable events that could occur during a regulatory control period, the AER considers it is appropriate to define a general set of circumstances, the occurrence of which will constitute a general pass through event.<sup>99</sup>

The AER also noted that an inability to recover costs associated with a material cost pass-through event is likely to impact on a regulated business' viability:

If an unforeseeable and uncontrollable event would have a material impact on a DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and NER, it is appropriate that costs associated with the event should be passed through to consumers.<sup>100</sup>

NT Gas agrees with this conclusion and considers that it has equal applicability to gas pipeline operators in providing reference services.

NT Gas also notes that its proposed approach is consistent with the revenue and pricing principles under section 24 of the NGL that require a service provider to be provided with a reasonable opportunity to recover at least the efficient costs the

---

<sup>98</sup> Rule 97(3)(d)

<sup>99</sup> AER 2009, *Australian Capital Territory distribution determination, 2009-10 to 2013-14: Final Decision*, p 128

<sup>100</sup> AER 2009, *Australian Capital Territory distribution determination, 2009-10 to 2013-14: Final Decision*, p 128



service provider incurs in providing reference services or complying with a regulatory obligation or requirement.<sup>101</sup> Arbitrarily limiting the recovery of costs associated with uncontrollable and unforeseen, or unforecastable events due to limitations in foresight on the part of either the service provider or the AER would not be consistent with this principle.

The AER's recent regulatory practice supports NT Gas' proposed approach. The AER has approved a general cost pass through event in each of its distribution network decisions made under the NGL and National Electricity Law.<sup>102</sup> At the same time, the AER has rejected a number of specific defined pass through events proposed by various proponents in favour of a general pass through event. NT Gas also notes that this approach is consistent with the regulatory arrangement in the earlier access arrangement where cost pass-through events, or imposts, were not specifically defined.

While not defining individual cost pass through events, NT Gas has included some examples in the access arrangement to assist the AER and prospective users to understand the expected scope of the cost pass-through reference tariff variation mechanism. The examples included in the access arrangement are:

- Changes in regulatory obligations, or the imposition of any new regulatory obligations, including changes to applicable laws, rules and regulations;
- A change in tax or levy, or the imposition of a new tax or levy; and
- An unusual or unforeseen event, such as a flood, cyclone or earthquake, that leads to costs not otherwise recovered or recoverable through insurance or other compensation payments.

NT Gas notes that each of these 'events' have been approved as specific pass through events for other service providers, including Jemena in respect of its NSW gas network<sup>103</sup>, and ActewAGL Distribution for its ACT network<sup>104</sup>, or included as general pass through events under the National Electricity Rules.

NT Gas submits that its proposed cost pass-through Reference Tariff variation 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<sup>105</sup>;

---

<sup>101</sup> National Gas Law section 24(2)

<sup>102</sup> For example, a general cost pass-through event was included in the NSW and ACT electricity determinations, the Jemena NSW, Country Energy Wagga Wagga and ACT access arrangements and the Queensland electricity determinations.

<sup>103</sup> AER 2010, *Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015, June*, clause 3.5C

<sup>104</sup> AER 2010, *Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015*, clause 6.24

<sup>105</sup> Rule 97(3)(a)





- is simple to understand and not burdened by legal jargon making it easier to comprehend and apply, thereby reducing compliance costs<sup>106</sup>;
- is consistent with the earlier access arrangement, in providing for a general cost pass through event definition<sup>107</sup>; and
- is consistent with recent AER decisions for similar services<sup>108</sup>.

### 11.3.3 Materiality threshold

As noted above, Rule 97(3) includes considerations for the AER in approving a reference tariff variation mechanism. In particular, 97(3)(b) states that the AER must have regard to “the possible effects of the mechanism on administrative costs of the AER, the service provider, and users or potential users”.

NT Gas proposes a materiality threshold to apply to the cost pass-through reference tariff variation mechanism of one per cent of the smoothed revenue requirement specified in the final decision in the years of the access arrangement period that the costs are incurred. This threshold is consistent with that approved by the AER for other service providers, including Jemena in respect of its NSW gas network, and ActewAGL Distribution for its ACT network.<sup>109</sup>

NT Gas submits that its proposed materiality threshold 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<sup>110</sup>;
- establishes a materiality threshold for cost pass through claims that reflects the administrative costs expected to be incurred by the AER, NT Gas and users in assessing claims changing tariffs<sup>111</sup>;
- is consistent with recent AER decisions for similar services<sup>112</sup>.

### 11.3.4 Tariff variation process

A key change in NT Gas’ access arrangement is in the tariff variation process. The former National Gas Code included a process for assessing tariff variations that is not reproduced in the Rules.<sup>113</sup> It is therefore necessary to include a tariff variation

---

<sup>106</sup> Rule 97(3)(b)

<sup>107</sup> Rule 97(3)(c)

<sup>108</sup> Rule 97(3)(d)

<sup>109</sup> AER 2010, Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015, clause 6.24

<sup>110</sup> Rule 97(3)(a)

<sup>111</sup> Rule 97(3)(b)

<sup>112</sup> Rule 97(3)(d)

<sup>113</sup> National Gas Code sections 8.3 -8.3H





process in the AGP access arrangement. NT Gas has designed the tariff variation process in the access arrangement to give the AER adequate oversight and powers of approval over variations to the reference tariff, as required under Rule 97(4), while also limiting unnecessary administrative costs.

NT Gas proposes to notify the AER of proposed tariff variations in accordance with either of the above mechanisms only where pipeline capacity to provide the reference service is available.

This approach limits the need to submit tariff variation notifications to the AER where there is no prospect that a user could contract on the basis of the reference service. This approach limits the administrative costs of regular tariff adjustments on NT Gas and the AER, where those adjustments would not apply to any current or prospective customer. This accords with Rule 97(3)(b). As the AER would assess all tariff variations where capacity is available, the AER will still be able to consider all proposed tariff variations to ensure they are compliant with the tariff variation mechanism in the access arrangement and relevant Rule requirements at the time they will apply to a particular user or prospective user. This gives the AER oversight of tariff variations as required under Rules 97(4).

NT Gas would only be required to submit annual tariff adjustment notifications to adjust for CPI and cost pass-through events where capacity is available. In the meantime, NT Gas would 'bank' CPI adjustments and cost pass-through events while no capacity is available, and should capacity become available, submit these to the AER for approval to vary the reference tariff at that time.

To assist the AER in assessing a tariff variation mechanism, NT Gas will include in its tariff variation notification information on how the change in the reference tariff has been calculated for each 1 July of the access arrangement period relevant to the notification (or since the last notification if such a notification has previously been made in the access arrangement period), as if a tariff adjustment notification had been made for each 1 July preceding the notification.

The notification may also include the impact of one or more cost pass-through events that have occurred, or are expected to occur. In this case the tariff adjustment notification will also include how any relevant change in costs associated with a cost pass-through event since the last notification have been derived or estimated.

The AER must notify NT Gas of its decision in respect of a tariff variation notification (relating to a CPI adjustment, a cost pass-through event or both) within 30 business days of receiving a notification. This timing is consistent with recently approved access arrangements for the NSW and ACT gas networks.<sup>114</sup> The AER's decision may relate to the variation of the reference tariff in line with the annual CPI tariff variation process, or at any other time during the access arrangement period.

If the AER does not make a decision within 30 business days, NT Gas proposes that the relevant reference tariff be automatically varied in accordance with the notification

---

<sup>114</sup> AER 2010, *Access Arrangement, JGN's gas distribution networks 1 July 2010 - 30 June 2015*, June, clause 3.4(d); AER 2010, *Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015*, clause 6.7 and 6.16



given by NT Gas. However, if the AER subsequently decides against all or part of the variation, the AER may require NT Gas to amend the reference tariff to take account of the AER's decision. A decision of this kind should leave NT Gas economically neutral compared with a situation in which the AER's decision had been implemented in accordance with the NT Gas notification. This automatic variation provision is essentially identical to that approved by the AER to apply in the ActewAGL Distribution ACT access arrangement.<sup>115</sup>

This approach provides certainty to NT Gas that costs associated with cost pass-through events are able to be recovered within a reasonable amount of time, ensuring that the reference tariff is set so as to give NT Gas a reasonable opportunity to recover at least the efficient costs it incurs in providing the reference service or complying with a regulatory obligation or requirement.<sup>116</sup> Delays in reflecting these costs in the reference tariff could undermine NT Gas' ability to deliver the reference service in the future, particular where there are significant adjustments to be made to the reference tariff.

NT Gas submits that its proposed tariff variation 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 unforeseen and uncontrollable costs to be reflected in the reference tariff<sup>117</sup>;
- does not require NT Gas to undertake the tariff variation notification process unless the reference service is available, thereby reducing administrative costs<sup>118</sup>; and
- provides the AER with adequate oversight and powers of approval over the variation of the reference tariff<sup>119</sup>.

---

<sup>115</sup> AER 2010, *Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2010-30 June 2015*, clause 6.17 and 6.18

<sup>116</sup> National Gas Law section 24(2)

<sup>117</sup> Rule 97(3)(a)

<sup>118</sup> Rule 97(3)(b)

<sup>119</sup> Rule 97(4)



# Attachment A – Information required by the National Gas Rules and AER Regulatory Information Notice

## Index of Information

This index of information provides cross-references to the documents that make up NT Gas' revised access arrangement proposal, providing the location of information submitted in compliance with the National Gas Rules or the AER Regulatory Information Notice.

**Table A.1 – Index of information**

| Source           | Requirement  | AA reference      | AAI reference | Submission  |
|------------------|--|-------------------|---------------|-------------|
| RIN 2.2(a)       | Provide a statement that the details of the service provider reported in the 2009-10 annual compliance report for the pipeline have not changed and remain relevant for the review of the pipeline |                   |               | 1.5.3       |
| RIN 2.2(b)       | Identify whether the service provider is a local agent of a service provider   |                   |               | 1.5.3       |
| RIN 2.2(c)       | Identify whether the service provider is acting on behalf of another service provider for the pipeline   |                   |               | 1.5.3       |
| NGR 48(1)(a)     | Identity of the pipeline to which the access arrangement relates and a reference to a website at which a description of the pipeline can be inspected  | 1.1               | 1.1           |             |
| NGR 48(1)(b)     | Description of the pipeline services the service provider proposes to offer to provide by means of the pipeline  | Part 2            | 10.1          | 2.1         |
| NGR 48(1)(c)     | Specification of the reference services  | 2.2               | 10.1          | 2.1.1       |
| NGR 48(1)(d)(i)  | The reference tariff for each reference service  | 4.1<br>Schedule 1 | 10.4          | 11.2.3      |
| NGR 48(1)(d)(ii) | The other terms and conditions on which each reference service will be provided  | 2.2<br>Schedule 3 |               | 2.2<br>11.3 |
| NGR              | Queuing requirements   | 6.1               |               |             |



| Source                  | Requirement   | AA reference | AAI reference | Submission              |
|-------------------------|---|--------------|---------------|-------------------------|
| 48(1)(e)                |   |              |               |                         |
| NGR<br>48(1)(f)         | Capacity trading requirements   | Part 5       |               | 2.2.1<br>2.2.3          |
| NGR<br>48(1)(g)         | Extension and expansion requirements  | Part 7       |               | 2.2.4                   |
| NGR<br>48(1)(h)         | Changing receipt and delivery points  | 5.4          |               | 2.2.1<br>2.2.3          |
| NGR<br>48(1)(i)         | Review submission and revision commencement dates   | 1.5<br>1.6   |               | 2.2.6                   |
| NGR<br>48(1)(j)         | Review expiry date (if relevant)  |              |               |                         |
| NGR 51                  | Trigger events (if relevant)  | N/A          | N/A           | N/A                     |
| NGR 99                  | Fixed principles  | 7.4          |               | 2.2.4                   |
| NGR 73                  | The basis on which financial information is provided must be stated and must use a recognised basis for dealing with inflation. All financial information must be provided on a basis that is consistent throughout the submission. |              | 1.2           | 1.3.3                   |
| NGR<br>72(1)(a)(i)      | Capital expenditure by asset class over the earlier access arrangement period   |              | 2.1           | 6.2.4                   |
| RIN 2.5.1.2(b)          | Explain significant variations between capital expenditure approved by the jurisdictional regulator and the actual and/or estimated capital expenditure for the earlier access arrangement period                                   |              |               | 6.2.1<br>6.2.2<br>6.2.3 |
| NGR<br>72(1)(a)(ii)     | Operating expenditure by category over the earlier access arrangement period  |              | 2.2           | 9.1                     |
| RIN 2.5.5.1(a)          | Provide an outline and explanation of the change in operating expenditure categories between the earlier access arrangement period and the access arrangement period  |              |               | 9.1                     |
| NGR<br>72(1)(a)(iii)    | Usage of the pipeline over the earlier access arrangement period, including   |              |               |                         |
| NGR<br>72(1)(a)(iii)(A) | minimum and maximum demand for each receipt or delivery point   |              | 2.3           | 5.1.1                   |
| NGR<br>72(1)(a)(iii)(B) | user numbers for each receipt or delivery point   |              | 2.3           | 5.1.2                   |



| Source          | Requirement  | AA reference | AAI reference | Submission              |
|-----------------|--|--------------|---------------|-------------------------|
| RIN 2.3(d)      | Explain any trends of demand and volumes over the earlier access arrangement period  |              |               | 5.1.1<br>5.2.2          |
| RIN 2.4(d)      | Explain any trends of pipeline capacity and utilisation over the access arrangement period   |              |               | 5.1.3                   |
| NGR 72(1)(b)    | Derivation of the capital base and a demonstration of the increase or diminution over the previous access arrangement period   |              | Chapter 3     | 7.1                     |
| RIN 2.5.1.1(a)  | Provide a reconciliation of the opening capital base at 1 July 2001 which adjusts for:<br>(1) differences between estimated and actual capital expenditure<br>(2) other relevant matters including for the weighted average cost of capital and indexation<br>(3) changes in asset classes between the earlier access arrangement period and the access arrangement period |              |               | 7.1.1<br>6.2.4          |
| RIN 2.5.1.1(b)  | Explain adjustments made referred to in RIN 2.5.1.1(a)   |              |               | 6.2.4                   |
| RIN 2.5.1.3(a)  | Identify assets that comprise the opening capital base which are or have been subject to compensation claims through, legal or court action, insurance or other processes  |              |               | 7.1.5                   |
| RIN 2.5.1.3(b)  | Provide details about the particular assets subject to such claims, time period of such claims, the relevant class of assets to which these assets belong  |              |               | 7.1.5                   |
| NGR 72(1)(c)(i) | The projected capital base over the access arrangement period including a forecast of conforming capital expenditure for the period and the basis for the forecast   |              | 3.2           | 7.2<br>6.2              |
| RIN 2.5.2.1(a)  | Describe and explain the nature of material forecast capital expenditure proposed in each asset class or capital expenditure category  |              |               | 6.2                     |
| RIN 2.5.2.1(b)  | Identify and explain the materiality threshold used to determine material forecast capital expenditure   |              |               | 6.2.2<br>6.3.1          |
| RIN 2.5.2.1(c)  | Identify the location of the proposed forecast capital expenditure   |              |               | 6.2.2<br>6.3.4<br>6.3.5 |



| Source         | Requirement   | AA reference | AAI reference | Submission  |
|----------------|---|--------------|---------------|---|
| RIN 2.5.2.1(d) | Provide relevant internal decision making documents relating to approval of the forecast capital expenditure and other internal or external documentation or models to justify the forecast conforming capital expenditure  |              |               | Chapter 4<br>Attachment C<br>Resource docs.                                     |
| RIN 2.5.2.1(e) | Explain whether the forecast conforming capital expenditure is to be funded by parties other than the asset owner   |              |               | 6.3.1   |
| RIN 2.5.2.1(f) | Provide details of contractual agreements with parties where capital contributions are made by users to new capital expenditure pursuant to rule 82   |              |               | 7.1.3   |
| RIN 2.5.2.1(g) | If Rule 79(2)(a) is relied on to justify new capital expenditure, provide<br>(1) a quantitative analysis which demonstrates how the capital expenditure is justifiable under Rule 79(2)(a); and<br>(2) an outline of the nature and quantification of the economic value that directly accrues to the service provider, gas producer, users and end users to address Rule 79(3)   |              |               | N/A   |
| RIN 2.5.2.1(h) | If Rule 79(2)(b) is relied on to justify new capital expenditure, provide a quantitative analysis that demonstrates the capital expenditure is justifiable under Rule(2)(b)   |              |               | 6.2.1<br>Attachment E   |
| RIN 2.5.2.1(i) | If Rules 79(2)(c)(i)-(iii) are relied on to justify new capital expenditure, as relevant:<br>(1) identify the statutory obligation or technical requirement and the relevant authority or body enforcing the obligations or requirement<br>(2) explain how the forecast capital expenditure satisfies the relevant statutory obligation or requirement; and<br>(3) provide supporting technical or other external or internal reports about how the forecast capital expenditure complies with the relevant statutory obligation or technical requirement |              |               | Chapter 3<br>6.2.1<br>6.2.2<br>6.2.3<br>6.3.3<br>6.3.4<br>6.3.5<br>Attachment D |
| RIN 2.5.2.1(j) | If Rule 79(2)(c)(iv) is relied on to justify new capital expenditure:<br>(1) quantify and explain the change in demand for existing services necessitating the new  |              |               | N/A   |



| Source         | Requirement  | AA reference | AAI reference | Submission            |
|----------------|--|--------------|---------------|-----------------------|
|                | capital expenditure; and<br>(2) provide reports or other information and documentation that supports how the forecast capital expenditure will meet the increase in demand for existing services.  |              |               |                       |
| RIN 2.5.6      | For each service provided by another party that contributes in a material way to the provision of the pipeline service(s) and is included in forecast capital expenditure, provide:<br>(a) the name of the external party and contract;<br>(b) details of how the contract was awarded (for example by competitive tender)<br>(c) details of fees and charges and a description of the goods and services provided<br>(d) the commencement date and term of the contract<br>(e) reasons why the functions were outsourced<br>(f) details of the relationships with the party or parties named in 2.5.4(a) and the service provider including id a party to the contract is an associate of any of the service providers of the pipeline;<br>(g) provide an explanation of the materiality measure used |              |               | 6.3.7<br>Attachment F |
| RIN 2.5.2.2(a) | If the speculative capital expenditure account has increased at a rate different to the rate of return implicit in a reference tariff<br>(1) identify the differences in rates; and<br>(2) explain why.  |              |               |                       |
| RIN 2.5.2.2(b) | Identify any mechanism which applies to prevent the service provider from benefiting, through increased revenue, from capital contributions made by a user in the access arrangement period  | 3.2          |               | 7.1.3                 |
| NGR 85         | Capital redundancy mechanism   | 4.9          |               | 2.2.5                 |
| NGR 85(3)      | Policies for other mechanisms (cost sharing if demand falls)   | 4.9          |               | 2.2.5                 |
| RIN 2.5.2.3(a) | If a mechanism to remove redundant assets is not proposed, explain why with a reference to the rules   |              |               | N/A                   |



| Source              | Requirement   | AA reference | AAI reference | Submission              |
|---------------------|---|--------------|---------------|-------------------------|
| NGR<br>72(1)(c)(ii) | The projected capital base over the access arrangement period including a forecast of depreciation for the period including a demonstration of how the forecast is derived on the basis of the proposed depreciation method |              | 3.2           | 7.2<br>7.2.3            |
| NGR<br>72(1)(d)     | A forecast of pipeline capacity and utilisation over the access arrangement period and the basis on which the forecast has been derived   |              | 4.1           | 5.2.5                   |
| RIN 2.3(a)          | Provide details of the key drivers behind the demand forecasts  |              |               | 5.2.2<br>5.2.3          |
| RIN 2.3(b)          | Explain and outline the methodology that has been used to support the demand forecasts, including the key assumptions and inputs that have been used and how demand for pipeline services is differentiated                 |              |               | 5.2.1<br>5.2.2<br>5.2.3 |
| RIN 2.3(c)          | Explain how demand forecasts have been used to develop the service provider's capital expenditure and operating expenditure forecasts   |              |               | 6.3.3<br>9.4.3          |
| RIN 2.3(d)          | Explain any trends of demand and volumes over the access arrangement period   |              |               | 5.2.2<br>5.2.3          |
| RIN 2.4(a)          | Provide details of the key drivers behind the forecasts of pipeline capacity and utilisation  |              |               | 5.1.3<br>5.2.5          |
| RIN 2.4(b)          | Explain and outline the methodology, including key assumptions and inputs, that have been used to prepare the forecasts of pipeline capacity and utilisation  |              |               | 5.2.5                   |
| RIN 2.4(c)          | Explain how the pipeline capacity and utilisation forecasts have been used to develop the service provider's capital expenditure and operating expenditure forecasts  |              |               | 6.3.3<br>9.4.3          |
| RIN 2.4(d)          | Explain any trends of pipeline capacity and utilisation over the access arrangement period  |              |               | 5.1.3<br>5.2.5          |
| NGR<br>72(1)(e)     | A forecast of operating expenditure over the access arrangement period and the basis on which the forecast has been derived   |              | Chapter 5     | 9.3                     |
| RIN 2.5.5.1(b)      | Provide a description and explanation of the nature of material forecast operating  |              |               | 9.3                     |





| Source       | Requirement   | AA reference | AAI reference | Submission          |
|--------------|---|--------------|---------------|---------------------|
|              | <p>expenditure in each operating expenditure category which:</p> <p>(1) outlines changes in the operations of the pipeline from the earlier access arrangement period that have resulted in material changes to operating expenditure category and total operating expenditure in the access arrangement period; and</p> <p>(2) identifies the materiality threshold used to determine the material forecast operating expenditure</p>  |              |               |                     |
| RIN 2.5.5.2  | Self insurance  |              |               | N/A                 |
| RIN 2.5.6    | <p>For each service provided by another party that contributes in a material way to the provision of the pipeline service(s) and is included in forecast operating expenditure, provide:</p> <p>(a) the name of the external party and contract;</p> <p>(b) details of how the contract was awarded (for example by competitive tender)</p> <p>(c) details of fees and charges and a description of the goods and services provided</p> <p>(d) the commencement date and term of the contract</p> <p>(e) reasons why the functions were outsourced</p> <p>(f) details of the relationships with the party or parties named in 2.5.4(a) and the service provider including id a party to the contract is an associate of any of the service providers of the pipeline;</p> <p>(g) provide an explanation of the materiality measure used</p> |              |               | 9.5<br>Attachment F |
| NGR 72(1)(f) | Key performance indicators used to support expenditure incurred over the access arrangement period  |              | Chapter 6     | 9.4                 |
| NGR 72(1)(g) | The proposed rate of return, the assumptions on which it was calculated and a demonstration of how it was calculated  |              | Chapter 7     | Chapter 8           |
| NGR 72(1)(h) | The proposed method of dealing with taxation, and a demonstration of how the taxation allowance is calculated   |              | Chapter 8     | 7.2.5               |



| Source           | Requirement   | AA reference | AAI reference | Submission      |
|------------------|---|--------------|---------------|-----------------|
| RIN 2.5.3(a)     | Explain and provide details of the proposed method for dealing with taxation and a demonstration or how the taxation is estimated   |              | Chapter 9     | 7.2.5           |
| NGR 72(1)(i)     | The proposed carry-over of increments from any incentive mechanism that operated in the earlier access arrangement period   |              |               |                 |
| RIN 2.5.4.1      | For each incentive mechanism which applied in the previous access arrangement period:<br>(a) provide an outline of how it operates;<br>(b) explain the increments for efficiency gains and decrements for efficiency losses that have occurred in the earlier access arrangement period and the relevant carryover amounts in the access arrangement period;<br>(c) provide relevant supporting analyses or reports |              |               |                 |
| NGR 72(1)(j)     | The proposed approach to price-setting including:   |              |               |                 |
| NGR 72(1)(j)(i)  | the suggested basis of reference tariffs (including the method used to allocate costs and a demonstration of the relationship between costs and prices) and   |              | 10.3          | 11.2.2          |
| NGR 72(1)(j)(ii) | a description of any pricing principles employed but not otherwise disclosed under this rule.   |              | N/A           | N/A             |
| RIN 2.6.1.1(a)   | Provide an outline of the nature of the allocation method used to allocate cost pools to reference and other services and provide analysis and information to support this allocation   |              |               | 11.1.2<br>4.4.1 |
| RIN 2.6.1.1(b)   | If relevant, for rebateable services, provide a description of the mechanism that the service provider 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  |              |               | N/A             |
| RIN 2.6.1.2      | For each reference service and for each user or class of users for a reference service for transmission pipelines   |              |               |                 |
| RIN 2.6.1.2(a)   | Outline the nature of:<br>(1) costs directly attributable to each reference   |              |               | 11.2.2          |



| Source         | Requirement  | AA reference | AAI reference | Submission |
|----------------|--|--------------|---------------|------------|
|                | service<br>(2) other costs that are attributable to reference services<br>(3) where relevant outline the costs directly and other costs attributable for the user or class of users and other users or classes of users  |              |               |            |
| RIN 2.6.1.2(b) | Explain and provide information about, the cost allocation method outlined in RIN 2.6.1.1(a)   |              |               | 11.1.2     |
| NGR 72(1)(k)   | The service provider's rationale for any proposed reference tariff variation mechanism   |              | 10.4.1        | 11.3       |
| RIN 2.6.2.2    | For each cost pass through mechanism   |              |               |            |
| RIN 2.6.2.2(a) | Define and describe each cost pass through event   |              |               | 11.3.2     |
| RIN 2.6.2.2(b) | Explain how each cost pass through event is relevant to a building block component in Rule 76 and is either foreseen or unforeseen and the costs of the event are uncontrollable and therefore cannot be included in forecasts for total revenue   |              |               | 11.3.2     |
| RIN 2.6.2.2(c) | Outline how the cost pass through mechanism gives the AER adequate oversight of powers of approval over variation of the reference tariff  |              |               | 11.3.4     |
| NGR 72(1)(l)   | The service provider's rationale for any proposed incentive mechanism  |              | Chapter 11    | 10.5       |
| RIN 2.5.4.2    | For each incentive mechanism proposed in the access arrangement period:<br>(a) provide an outline of how it operates<br>(b) explain its rationale including how it is intended to encourage efficiency of the provision of services and is consistent with the revenue and pricing principles<br>(c) provide relevant supporting analyses or reports |              |               | 10.5       |
| NGR 72(1)(m)   | The total revenue to be derived from pipeline services for each regulatory year of the access arrangement period   |              | Chapter 12    | 10.4.1     |
| NGR 84         | Speculative capital expenditure account  | 3.2          |               |            |
| NGR 86         | Re-use of redundant assets   |              |               | N/A        |



| Source    | Requirement   | AA<br>reference | AAI<br>reference | Submission |
|-----------|---|-----------------|------------------|------------|
| NGR 90(2) | Whether depreciation for the opening capital base is based on actual or forecast depreciation | 3.5             |                  |            |



## **Attachment B – Regulatory Information Notice templates**

Templates are provided separately





## **Attachment C – Planning documents**

C.1 – Asset Management Plan (confidential)

C.2 – Pipeline Management Plan (confidential)

Provided as separate documents







## **Attachment D – Channel Island Meter Station project – confidential**

***Box D.1 – Channel Island Meter Station Upgrade***





## **Attachment E – Models**

E.1 – Roll Forward Model

E.2 – Tax Roll Forward Model

E.3 – Post Tax Revenue Model

E.4 – Net Present Value evaluation of Katherine Meter Station upgrade

These models are provided separately





## Attachment F – Details of outsourced expenditure – confidential

*Table F.1 – Details of outsourced capital expenditure over the access arrangement period*





## **Attachment G – Estimating a WACC for the NT Gas Transmission Pipeline**

Provided as a separate document







## **Attachment H – WACC information – confidential**

Provided as a separate document





## **Attachment I – Operating expenditure base year adjustments and step changes – confidential**

*Table I.1 – Operations and maintenance category base year adjustments and step changes*