ECG

energy consulting group

# Review of Country Energy Gas

# Gas Access Arrangement

# For

# Independent Pricing and Regulatory Tribunal

*14 June 2005*

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## DISCLAIMER

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# 1. EXECUTIVE SUMMARY

**Background**

Country Energy Gas (CEG), formerly named Great Southern Energy Gas Networks (GSEGN) first Access Arrangement came into effect on 1 October 1999 and was to operate until December 2003. Following requests from CEG the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) agreed to extend the Access Arrangement period to 31 December 2004.

In December 2003, CEG submitted its proposed Access Arrangement revisions relating to the Wagga Wagga natural gas distribution system in NSW to the Tribunal.

The Tribunal subsequently engaged Energy Consulting Group (ECG) to conduct a review of CEG's capital and non capital expenditure (together referred to as 'total cost') to assist the Tribunal in its assessment of the proposed Access Arrangements.

As part of the review process, ECG visited the Wagga Wagga gas network to gain an appreciation on the network operation activities. ECG also sought additional information from CEG. This was a protracted process and in a number of cases, CEG has not been able to respond to the questions fully which has resulted in ECG making a number of assumptions.

For the ease of comparison between years, ECG has carried out the review in 2005/06 dollars (unless otherwise stated).

**Capital Expenditure 1999 to 2003**

CEG's actual capital expenditure for the current period is summarised in Table 1-1, together with the total forecast allowances. It should be noted that 2003 actual expenditure is an estimate as advised by CEG.

**Table 1-1 New Facilities Investment in the First Access Arrangement Period (Real $ thousand 2005/06)**

| Calendar years | 1999 | 2000 | 2001 | 2002 | 2003 (est)[1] | Total |
|---|---|---|---|---|---|---|
| **Asset replacement & refurbishment** | | | | | | |
| **- pipes** | 270 | 389 | 280 | 155 | 264 | **1,357** |
| **- meters** | 317 | 496 | 330 | 143 | 88 | **1,373** |
| **Growth Related** | 1,503 | 1,923 | 1,426 | 1,571 | 1,148 | **7,571** |
| **Non-system assets, FRC** | 0 | 48 | 395 | 371 | 491 | **1,305** |
| **Southern Gate Station** | 0 | 875 | 1,099 | 122 | 24 | **2,120** |
| **Actual Capital Expenditure** | **2,090** | **3,731** | **3,530** | **2,362** | **2015** | **13,726** |

**Note:** The data in this table is different to the Actual Expenditure in Table 4.1 in the December 2003 AAI as it has been converted to 2005/06 dollars and has reallocated costs between Non-system assets and Growth Related as advised by CEG.

[1] CEG estimate in 2003 AAI

The key findings of the review carried out by ECG are as follows:

- CEG deferred its refurbishment/rehabilitation program as a result of diverting its resources to growth related capital program. There was however, no information on the risk or the impact of this deferral. However, ECG considered that the rehabilitation expenditure for the length of mains replaced/refurbished was prudent and efficient.

- The cost of CEG meter change program as part of its statutory obligation was considered high by ECG especially in comparison to AGLGN.

- The Glenfield Road project was a major reinforcement project. ECG considers the cost of the project to be high.

- ECG considers the cost of expansion of natural gas to Uranquinty customers to be in accordance with the Code.

- The Southern Gate Station is a major reinforcement and security of supply project in Wagga Wagga. The Tribunal in its Final Decision 1999 allocated a capital expenditure equivalent to an alternative project of Looping. ECG concurs with the option adopted by CEG for reasons outlined in the report.

ECG recommends the following capital expenditure for inclusion into CEG's asset base:

**Table 1-2 Recommended Capital Expenditure 1999 to 2003**
**(Real $ thousand 2005/06)**

| Calendar years | **1999** | **2000** | **2001** | **2002** | **2003** | **Total** |
|---|---|---|---|---|---|---|
| Asset Replacement and Refurbishment | 542 | 812 | 566 | 288 | 358 | 2,566 |
| Growth Related | 1,210 | 1,633 | 1,269 | 1,353 | 974 | **6,439** |
| Non System Assets/ FRC | 0 | 48 | 395 | 371 | 491 | **1,305** |
| Southern Gate Station | 0 | 875 | 1,099 | 122 | 24 | **2,120** |
| **Total** | **1,752** | **3,368** | **3,329** | **2,134** | **1,847** | **12,430** |

**Capital Expenditure 2004 – 2010**

Due to delays in the review process, the revised Access Arrangement for CEG is now expected to commence in July 2005. This means that there is a transitional period from the expiry of the current Access Arrangement in December 2003 to the start of the new period in July 2005.

ECG has analysed the cost for the transitional period together with the expenditure for the revised Access Arrangement period. CEG's forecast capital expenditure is shown in Table 1-3.

**Table 1-3 Forecast New Facilities Investment 2004 to 2010**
**(Real $ thousand, 2005/06)**

| Financial Years | 2004 Calendar year | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Mains Rehabilitation** | 759 | 315 | 603 | 758 | 628 | 636 | 725 | **4,423** |
| **Meter Replacement** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **860** |
| **Growth Related** | 844 | 428 | 896 | 842 | 825 | 788 | 838 | **5,462** |
| **Non-system assets** | 268 | 131 | 264 | 264 | 264 | 264 | 265 | **1,720** |
| **Total** | **1,956** | **917** | **1,854** | **1,968** | **1,869** | **1,878** | **2,024** | **12,465** |

The key findings from the review carried out by ECG are as follows:

- CEG's proposal of replacing 2.5% p.a. of the galvanised steel mains is considered prudent and efficient in accordance with the Code. Based on the information provided, ECG believes that there is no justification to accelerate the rate of replacing the cast iron. ECG considers that a replacement rate equivalent to that of the first period would be considered prudent and efficient in accordance with the Code.

- The forecast expenditure for new customers is considered to be high. The mains unit cost is considerably higher than the current Access Arrangement period.

- The proposed Wagga Wagga ring main cannot be justified at this stage..

- CEG proposes a number of IT projects over the forecast period. The projects include an asset management system, gas network billing and middleware products. Such projects are what would be expected of a prudent network service provider, however ECG believes that the cost of the Middleware is higher than what would be considered efficient.

ECG therefore recommends the following capital expenditure for the next Access Arrangement period:

**Table 1-4 Recommended Capital Expenditure 2004 to 2010**
**(Real $ thousand 2005/06)**

| | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **Mains Rehabilitation** | 418 | 225 | 466 | 497 | 526 | 553 | 578 | **3,263** |
| **Meter Replacement** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **860** |
| **Growth Related** | 479 | 240 | 485 | 442 | 416 | 381 | 441 | **2,884** |
| **Non-system assets / FRC** | 248 | 123 | 245 | 245 | 245 | 245 | 245 | **1,596** |
| **Total** | **1,230** | **631** | **1,287** | **1,288** | **1,339** | **1,369** | **1,460** | **8,603** |

**Non Capital Expenditure**

ECG's review of the current Access Arrangement period 1999 to 2003 was used as the basis for reviewing the Non Capital Costs for the next AA period.

CEG proposed non capital expenditure for the period from January 2004 to July 2010 is as shown in Table 1-5

**Table 1-5 CEG Forecast Non Capital Cost 2004 to 2010 (Real $ 2005/06)**

| | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Network Operating and Maintenance** | 969 | 499 | 997 | 997 | 997 | 997 | 997 | **6,453** |
| **Marketing** | 142 | 73 | 146 | 146 | 146 | 146 | 146 | **945** |
| **Direct Network Gas Management** | 447 | 224 | 448 | 448 | 448 | 448 | 448 | **2,910** |
| **Corporate Allocation** | 606 | 303 | 607 | 607 | 607 | 607 | 607 | **3,943** |
| **FRC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Regulatory Costs** | 0 | 26 | 52 | 52 | 52 | 52 | 52 | **288** |
| **Service Standards Administration** | 0 | 10 | 21 | 21 | 21 | 21 | 21 | **115** |
| **Total** | **2,164** | **1,136** | **2,271** | **2,271** | **2,271** | **2,271** | **2,271** | **14,656** |

The key findings from the review carried out by ECG are as follows:

- Network Operating and Maintenance (O&M) expenditure with an efficiency factor of 1.5% is considered to be efficient in accordance with the Code.
- Marketing annual expenditure is approximately 40% higher than the 2003 expenditure. ECG considers this cost to be high especially when it is forecast that the number of customers will decrease in the forecast period.
- The Direct Network Gas Management cost with an efficiency factor of 1.5% is considered efficient in accordance with the Code.

ECG therefore recommends the following non capital costs in accordance with the Code.

**Table 1-6 Recommended Non Capital Expenditure 2004 to 2010 (Real $ thousand 2005/06)**

| | 2004 | Jan – June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Totals |
|---|---|---|---|---|---|---|---|---|
| **Network O&M** | 956 | 492 | 987 | 992 | 990 | 989 | 986 | **6,392** |
| **Marketing** | 112 | 56 | 112 | 112 | 112 | 112 | 112 | **728** |
| **Direct Network Gas Management** | 441 | 221 | 441 | 446 | 444 | 444 | 443 | **2,880** |
| **Corporate Allocation** | 511 | 256 | 511 | 511 | 511 | 511 | 511 | **3,322** |
| **FRC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Regulatory Costs** | 0 | 26 | 52 | 52 | 52 | 52 | 52 | **286** |
| **Service Standards Administration** | 0 | 10 | 21 | 21 | 21 | 21 | 21 | **115** |
| **Total** | **2,020** | **1,060** | **2,124** | **2,134** | **2,130** | **2,129** | **2,125** | **13,723** |

# 2. INTRODUCTION

## 2.1 BACKGROUND

Country Energy Gas (CEG), formerly named Great Southern Energy Gas Networks (GSEGN), first Access Arrangement came into effect on 1 October 1999 and was to operate until December 2003. Following requests from CEG the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) agreed to extend the Access Arrangement period to 31 December 2004.

In December 2003, CEG submitted its proposed Access Arrangement revisions relating to the Wagga Wagga natural gas distribution system in NSW to the Tribunal. CEG's submission is to be reviewed by the Tribunal under the National Third Party Access Code for Natural Gas Pipeline Systems (the Code).

The Tribunal subsequently engaged Energy Consulting Group (ECG) to conduct a review of CEG's capital and non capital expenditure (together referred to as 'total cost') to assist the Tribunal in its assessment of the proposed Access Arrangements.

## 2.2 OBJECTIVES OF CONSULTANCY

The primary objective of ECG's consultancy is to apply Section 8 of the Code to:

- Make recommendations on actual and forecast capital expenditure undertaken in the course of the current Access Arrangement.
- Analyse capital expenditure forecast for the period of the proposed revised Access Arrangement.
- Report on any possible capital redundancy in CEG assets.
- Analyse CEG forecast non-capital costs.

# 3. REVIEW PROCESS

## 3.1 INTERPRETATION OF THE CODE

In undertaking this study, ECG took into consideration the requirements of the Code. In particular:

- Sections 8.16 to 8.19 of the Code which set out how the capital base of a pipeline can be increased by actual capital expenditure and sections 8.20 to 8.22 which deal with forecast capital expenditure.
- Sections 8.36 and 8.37 which define non capital costs and outline the criteria for acceptance.

Both sections 8.16(a) and 8.37 of the Code require that costs must not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice and to achieve the lowest sustainable cost of delivering Services and Reference Services.

The Tribunal has defined "prudent" and "efficient" as follows:

- 'Prudent' as meaning discreet or cautious in managing one's activities; practical and careful in providing for the future and exercising good judgement.
- 'Efficient' as meaning functioning or producing effectively and with the least waste of effort.

ECG has interpreted the Tribunal's definition of 'efficient' as also meaning that capital and non capital expenditure should reflect competitive market rates and has applied this interpretation in conducting its assessment.

"Good industry practice" is considered to mean the practice that a prudent operator would adopt in similar Australian conditions and 'lowest sustainable cost' as meaning an optimum balance of capital and non capital expenditure that maintains the safety and integrity of the assets throughout their economic lives. In CEG's case, the majority of its network assets are long-life – up to 80 years.

ECG has endeavoured, as far as practicable, to take the life-cycle requirements of each asset category into account. Specific details of how ECG has applied the above principles to its assessment of capital and non capital expenditure are outlined in relevant sections.

## 3.2 APPROACH

In undertaking its assessment, ECG adopted the following general approach:

- Reviewed CEG's proposed Access Arrangement (AA) and Access Arrangement Information (AAI) submitted to the Tribunal in December 2003.
- Met with CEG staff in Wagga Wagga to obtain an appreciation of CEG's Wagga Wagga network operations and to facilitate initial questioning by both parties. This included site visits to a limited number of facilities and to assist ECG gain an understanding of the size and extent of the network.

- ECG subsequently raised a number of questions seeking more information and clarification relating to a wide range of issues pertaining to CEG's submission. This was a protracted process.

- A register was established to record and manage the questions and responses and the numbering system adopted is referenced in this report by the insertion of footnotes.

- ECG conducted its assessment based on the available information/data. It should be noted that CEG was unable to fully respond to all ECG's requests; ECG's analysis is constrained accordingly. The availability of key asset management operational and financial data is limited. Any assumptions made by ECG are clearly explained in the report as is the derivation of any data.

To facilitate period comparisons, ECG has carried out its review in 2005/06 real dollars.

ECG has also considered the following:

- Gas Supply Act 1996.

- Current demand and likely future demand as forecast by CEG.

- CEG current Access Arrangement and Access Arrangement Information.

- Trade-offs between capital and non capital expenditure.

- Capital contributions by users.

## 3.3 STRUCTURE OF THE REPORT

The report has been divided into the following sections:

- Section1 - Executive Summary.

- Section 2 - Introduction.

- Section 3 - Approach adopted by ECG.

- Section 4 – Description of network assets.

- Section 5 - CEG asset management process.

- Section 6 – 1999 – 2003 Capital expenditure

- Section 7 – 2004 – 2010 Capital expenditure

- Section 8 - 1999 – 2003 Non capital expenditure

- Section 9 - 2004 – 2010 Non capital expenditure.

# 4. DESCRIPTION OF COUNTRY ENERGY GAS NETWORK

## 4.1 GENERAL OVERVIEW

Gas has been available in Wagga Wagga since the late 1880s. Manufactured gas was provided from this time until 1981 when supplies from the Cooper Basin became available via a new lateral pipeline connecting Wagga Wagga and Cootamundra with the Moomba to Sydney Pipeline at Young. The gas supply was managed by the Wagga Wagga City Council until the system was acquired by Great Southern Energy, a company owned by the New South Wales Government, in June 1997.

Great Southern Energy, along with Advance Energy and NorthPower (both also owned by the New South Wales Government) were merged to form Country Energy on 1 July 2001. The gas distribution system is owned and operated by Country Energy Gas Pty Limited (CEG), a subsidiary of Country Energy

More than 550km of mains supply natural gas to over 16,500 customers, mostly domestic and small commercial categories. Several large Contract Customers account for around 48% of total gas sales by volume.

### 4.1.1 Receipt Points

. There are two receipt points for the network:

- The original city gate at Bomen, on the north side of the city which connects with the Young to Wagga Wagga Pipeline, owned by East Australian Pipeline Limited (EAPL).
- The southern gate station near the township of Uranquinty, constructed in 2000-01, which connects with EAPL's Wagga Wagga to Culcairn Pipeline (which connects with GasNet's Victorian gas transmission network at Culcairn.

Hence, there is potential for gas to flow to Wagga Wagga from either the Cooper Basin or the Gippsland Basin, depending upon the direction of flow in the transmission system.

### 4.1.2 Gas Distribution Systems

The CEG network operates at different pressures depending on the location within the network. The pressures in the system are shown in Table 4-1.

**Table 4-1 Pressures in the Networks**

| Pressure Networks | Pressure kPa |
|---|---|
| High Pressure | 400-1050 |
| Medium High Pressure | 80-400 |
| Medium Low | 7-80 |
| Low | 4-7 |

The low pressure system, which is dispersed through the network, is supplied from receipt points by 61,972 metres of steel high pressure mains (to API 5L specification). The gas pressure from the supply mains is then reduced by a district regulator before the gas enters each supply district.

The low pressure system is progressively being replaced/refurbished and operating pressures increased.

The pipes in the older gas networks are generally cast iron or galvanised steel. The pipes in the more recent low pressure areas are mainly plastic pipes (nylon and polyethylene).

### 4.1.3 Pressure Control

At the two gate stations, pressure is reduced from a maximum operating pressure of approximately 7000 kPa to approximately 1000 kPa. The Bomen City Gate incorporates two streams of two stage pressure reduction regulators with monitor override and a relief valve. The Uranquinty City Gate comprises a single stream single stage pressure reduction using an Active/ Monitor configuration with over-pressure protection.

Gas from the Bomen City Gate is supplied via a steel main to the Bomen industrial area and via a ring main to the Wagga Wagga central business district. A 110mm diameter polyethylene secondary ring main supplies the southern area of Wagga Wagga. Two extensions from the secondary ring main run to the Kapooka army base, south-west of the city and to the Forest Hill air force base, east of the city.

The domestic metering pressure is predominantly 1.5 kPa but 2.75 kPa is used in some districts.

## 4.2 CONDITION OF ASSETS

Most of CEG's galvanised steel network was constructed between 1950 and 1980. Based on field data and engineering forecasts, CEG has estimated a median life of 50 years for these assets. It has assessed that a growing proportion of this network will require replacement over the period to 2017 and accordingly, CEG proposes to replace 2.5%[2] of the network each year over the forthcoming regulatory period.

The CEG network also includes 44 kilometres of cast iron mains, the last of which were laid in the early 1990s. A proportion of the cast iron network has already been rehabilitated. Priority for rehabilitation of cast iron mains is determined primarily by information generated from leak surveys. CEG advises that replacement will be undertaken where it is considered more prudent than repair or where there is insufficient capacity available in existing mains.

Leaks per kilometre of mains surveyed in 2000, 2001 and 2002 were 0.5, 0.23 and 0.71 respectively[3]. This number of leaks per kilometre is comparable with the range of 0.54 to 0.7 for the Victorian networks[4] where, like Wagga Wagga, a significant proportion of ferrous mains remain.

The renewal program seeks to progressively eliminate the existing 7kPa and 20 kPa systems. Renewed sections of mains will be installed to a standard that allows a pressure range of 200-400 kPa.

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[2] CEG states in the AAI that 'a growing proportion' of the galvanised network will require replacement over the period to 2017. About 182km remains and if CEG replaces 2.5%/yr over the forecast 6.5 year period 2004-2009/10 this equates to about 30km, leaving about 150km to replace post this period (up to about 2030 which is 1980 + 50 years.)

[3] CEG Safety & Operating Plan December 2002

[4] ECG Review of AGLGN Gas Access Arrangements for IPART July 2004

# 5. ASSET MANAGEMENT

## 5.1 ASSET MANAGEMENT PLANS

Network assets predominantly comprise long life gas mains, services, (pipes which convey gas from the mains to the customer meter/regulator), regulators and meters. A network operator's Asset Management Plan (AMP) provides the strategic direction for the management of these assets in the longer term. Typically an AMP includes strategies for:

- Operation and maintenance.
- Capacity management.
- Asset replacement.
- Information technology system development.

A network operator's Safety and Operating Plan (SAOP) is developed to ensure the safe operation of the network and typically includes an outline of the day-to-day activities necessary to achieve this objective.

At its meeting with ECG in Wagga Wagga CEG advised that one of its Business Plan initiatives for 2004/05 is to develop an AMP to detail the maintenance and replacement strategies for its assets. Currently CEG's SAOP is the catalyst for asset replacement and refurbishment.

ECG believes that CEG's SAOP is adequate for ensuring the safe and reliable operation of the network. However considerable reliance appears to be placed on historical maintenance practices and the system knowledge of a few key operational personnel.

Although the network is relatively small, ECG strongly supports CEG's initiative to develop an AMP that provides a strategic direction for the ongoing management of the assets. It is ECG's view that for this future management to be fully effective it must be underpinned by a suitable strategic framework.

## 5.2 SAFETY AND OPERATING PLAN

CEG is the "Authorised Reticulator" for its gas network in NSW as defined in the *Gas Supply Act 1996* (NSW). The Safety and Operating Plan (Plan) for the NSW Distribution Network has been prepared by CEG to ensure the safe operation of the network in NSW. It has been written in accordance with the Gas Supply (Network Safety Management) Regulation 2002 made under the *Gas Supply Act.* The Plan forms the basis by which CEG fulfils its legal obligations under the Act.

ECG was provided with a copy of the Plan (dated December 2002) for the purposes of this report and has reviewed its contents.

The Plan comprises the following:

- A background statement that includes the objectives of the Plan.
- A description of each of the gas networks owned by CEG, including relevant maps.
- Load capacities of the various subdivisions within the Wagga Wagga network predicted by computer modelling.

- Risk assessments including identified threats and the design, operational and maintenance measures required to eliminate or reduce these threats to as low as reasonably practicable (ALARP).

- An outline of the standards, policies and procedures, which CE follows in the design, construction, operation and maintenance of the network.

- A summary of the emergency response plans.

- CEG's requirements for gas quality and pressure standards and the procedures which have been implemented to ensure that gas conveyed in the network meets those standards and is odorised to an appropriate level.

- A summary of CEG's records management arrangements.

- A description of administrative arrangements by which the Plan is implemented.

- A chart setting out the structure of the CEG organization.

The format of the document follows the recommendations of the draft Australian Gas Association AG606 Code of Practice for the Preparation of a Safety Case for Gas Networks. It is a master document that summarises and references a number of sub plans and other documents that detail the management strategies and programmes.

As the Plan has been prepared in accordance with the requirements of the Gas Supply Regulations, ECG considers that CEG's Plan is what would be expected from a prudent operator as required under the General Principles of the Code, section 8.1(c) which states "A Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objective – ensuring the safe and reliable operation of the Pipeline"

## 5.3 NETWORK CAPACITY PLANNING

Network Capacity Planning is a key function that underpins the capital expenditure program. It is fundamental to assessing the capability of gas networks to deliver gas loads to all customers prudently and efficiently, as required under section 8.16 of the National Third Party Access Code.

The four principal activities in the planning process include:

- Forecasting peak loads.

- Modelling current network performance.

- Predicting future network performance and reinforcement timing.

- Specifying projects for inclusion in the capital expenditure program.

CEG perform these four principal activities as described below, enabling them to make network capacity assessments and to plan projects to overcome capacity limitations.

### 5.3.1 Peak Load Forecasting

A forecast of annual sales for each year is produced. A forecast of peak day loads from historical data and annual sales forecasts for contract and volume customers is also produced[5]. These provide a basis for estimating growth in peak day loads.

A review of the annual sales forecasts is being undertaken separately by McLennan Magasanik Associates.

ECG considers the process for estimating peak day loads to be consistent with that which would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

### 5.3.2 Network Performance Modelling

Network modelling is a tool used by a gas distribution business to predict the future performance of its networks and to plan the additional facilities necessary to supply the future peak loads. This is then used to determine the areas that require reinforcement to ensure that the business can continue to provide its reference services.

CEG have advised that network modelling is conducted using "GAS WORKS" flow modelling software. ECG has reviewed typical modelling results for the principal high pressure network[6] and considers the results reasonable. ECG is therefore of the view that the software is appropriate for modelling the Wagga Wagga network.

However CEG advises that it does not have models for its entire network. In addition, CEG does not have a process for validating the existing network model. CEG advises they are currently reviewing their model for the principal high pressure network[7] and intend to develop models for other key networks.

ECG considers that all key networks should have network models that are validated regularly to ensure their accuracy. It is expected that the models need to be validated at a frequency between once every year and once every five years depending upon the load and growth rate.

ECG therefore believes that a prudent operator would ensure that it has models for all key sections of its network and ECG recommends that CEG carries out its proposed review of the principal high pressure network model and develops models for its other key networks. It is expected that as CEG currently has the modelling software, the development of network models would be carried out by CEG network planning engineer as part of its ongoing responsibility.

### 5.3.3 Network Performance and Augmentation Timing

Unlike modelling of the network which is used for determining the extent of any reinforcement required, a gas distribution business would also carry out monitoring of the pressures in the network to assess the performance of the networks. CEG advises that it monitors networks performance each year by measuring minimum network pressures at key locations. It indicates that about 20 locations were monitored during year 2004[8]. ECG

[5] IRS, Load Forecast Report, Wagga Wagga Gas Network, December 2003, Section 7
[6] Wagga Wagga Natural Gas Distribution Network 1998 Capacity Analysis, Appendix B
[7] CEG Email, Issue 1.8, 12 October 2004
[8] CEG Email, Issue 1.14, 12 October 2004

considers that the monitoring carried out in 2004 is appropriate for the complexity and size of Wagga Wagga network.

Results from this program are used to identify those networks where minimum pressures are close to or below the minimum allowable values, which are as specified in Table 4-1. In addition to the network monitoring, CEG advises that it uses the history of customer complaints in particular locations to assess the performance of the networks.

ECG believes whilst the monitoring of pressures in the network provides CEG with the information on the timing of any reinforcement required, it is inadequate to determine the extent of reinforcement. Such a process has the potential to create the following issues:

- Provide excess reinforcement and unnecessary capital expenditure if too many or inappropriate reinforcement projects are implemented.
- Risk gas supply outages if insufficient or inappropriate reinforcement projects are implemented.

ECG considers that an improved reinforcement planning program should be implemented by CEG, to effectively validate and report on the performance of all key networks and identify appropriate augmentation projects. This should be based on the CEG current pressure monitoring program and the expanded network modelling it plans to implement.

## 5.4 CAPEX PROCESS

Under Sections 8.16 and 8.17 of the National Third Party Access Code for Natural Gas Pipeline Systems, capital expenditure must be prudent and efficient to be accepted for inclusion in the Capital Base.

It must not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice and to achieve the lowest sustainable costs of delivering services. In addition it must satisfy one or more of the following conditions:

1. The anticipated incremental revenue generated by the new facility exceeds the new facilities investment; or
2. The service provider and/or users satisfy the relevant regulator that the new facility has system wide benefits that, in the relevant regulator's opinion, justify the approval of a higher reference tariff for all users; or
3. The new facility is necessary to maintain the safety, integrity or contracted capacity of services.

CEG provided a copy of its Network Capital Expenditure Procedure [9] which outlines its approach to assessment, approval, monitoring and effective control of capital expenditure on its network. This procedure includes:

- A statement of the procedures purpose, obligations to be met and stakeholders to be considered in assessing projects.
- Details of the actions required by and responsibilities of persons authorised to approve capital expenditure, including post implementation reviews for projects > $100,000.

[9] Country Energy Procedure, CEP2008.

- Details of delegated capital expenditure authorisation levels, as shown in Appendix 1.
- A process for prioritisation of essential network projects.
- Requirements for recording of capital expenditure projects.
- Business Case requirements including expenditure details, purpose of expenditure, options considered and cost/benefit analysis or formal financial evaluation for expenditure > $100,000. Further details on the requirements for this are provided in a separate procedure[10]
- Supplementary submission requirements to obtain approval for additional funds for projects where expenditure will exceed that approved by more than the allowable variation shown in Appendix 1.
- Post expenditure review requirements.

Following Board approval of the annual capital budget, each project must be approved by the appropriate manager within delegated authorisation levels.

Following discussions with some CEG Managers, ECG has concluded the managers are aware of the expenditure delegation levels and that they are required to work within the delegated levels.

CEG advises[11] that each authorisation request includes a job description, purpose of the proposed work, options considered, financial implications, impact on the existing capital works program, project benefits and recommendations. ECG has reviewed board papers and minutes and a recent authorisation request and believes that CEG Capital Expenditure Procedure is being followed.

Assessments for the two major projects of the current access arrangement period have been provided by CEG[12] and confirm that in each case project objectives have been achieved for costs significantly under budget. These assessments meet CEG requirements for post implementation reviews of these projects.

CEG advises[13] that the required rate of return for each project is [Confidential][14] pre tax real, compared with the WACC of 7.75%pa pre tax real rate of return in the current Access Arrangement period. Financial evaluation is based on a 20 year project life.

ECG considers that an overall pre-tax real rate of return of 8%pa is at the low end of a commercially acceptable range. It considers that a higher rate of return may be prudent for individual projects, to offset lower returns achieved on some projects deemed to be essential for reasons such as public safety. This is consistent with the approach adopted by AGLGN.

ECG considers the capital expenditure process to be what would be expected from a prudent operator acting efficiently, consistent with good industry practice and in accordance with the requirements of Section 8.16 of the Code.

Developer capital contributions are obtained if relevant and necessary to meet the hurdle rate (refer Sections 6.8 and 7.7 for further review of capital contributions requirements).

[10] Country Energy Procedure, CEP2009
[11] CEG Email, Issue 3.1, 27 September 2004
[12] CEG Emails, Issue 6.17/6.18, 22 October 2004
[13] CEG Email, Issue 1.5.1, 22 October 2004
[14] CEG may consider this information commercial in confidence.

# 6. CAPITAL EXPENDITURE REVIEW 1999 TO 2003

## 6.1 CEG OPENING CAPITAL BASE

Section 8.9 of the Code generally provides for the regulatory capital base to reflect the initial capital base at the start of the Access Arrangement period, adjusted for capital expenditure (which passes the test in Section 8.16 of the Code), depreciation, redundant capital, asset disposals, capital contributions and inflation of the asset base.

Section 8.16 of the Code enables capital expenditure in the Access Arrangement period to enter the regulatory capital base provided that:

- The amount does not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice and to achieve the lowest sustainable cost of delivering services.
- One of the following conditions is satisfied:
  - The anticipated incremental revenue generated exceeds the cost.
  - The regulator is satisfied that the capital expenditure has system-wide benefits that justify the approval of a higher reference tariff for all users.
  - The capital expenditure is necessary to maintain the safety, integrity or contracted capacity of services.

The Code does not specifically outline the approach that has to be adopted to determine the efficient cost for a level of service. As such, ECG has assessed the capital costs in the following manner, by:

- Reviewing the capital expenditure in the Access Arrangement Information and taking into consideration the Tribunal's decision in the 2000 Access Arrangement.
- Reviewing actual costs to assess trends, anomalies, differences in the various input categories.
- Analysing the input categories to determine the reasonableness of the costs for the service provided.
- Where possible, comparing overall costs in particular categories (e.g. growth related costs) with those of other companies.
- Reviewing the CEG forecasts of costs and the methods and the processes and data used to derive them.
- Concluding the efficient cost for the 1999 to 2003 Access Arrangement period after taking into account the various input factors.

Details of the assessment are provided in the following sections of this review.

CEG has set out its calculation of the Regulatory Capital Base in the Access Arrangement Information[15]. CEG advises that subsequent to its December 2003 AAI proposal, changes have been made to depreciation in 2000, 2001, 2002, 2003 and that the revised Regulatory Capital Base is as shown in Table 6-1[16].

[15] AAI, Table 4.3, December 2003
[16] CEG email, Issue 6.4, 3 August 2004

**Table 6-1 Calculation of the Capital Base at 1 January 2004 (Nominal $ thousand)**

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 (est) | TOTAL |
|---|---|---|---|---|---|---|
| **Opening Capital Base** | **28,000** | **29,124** | **32,335** | **36,127** | **38,323** | **-** |
| **Capital Expenditure** | 1,713 | 3,197 | 3,156 | 2,176 | 1,908 | **12,150** |
| **Depreciation** | 996 | 1,052 | 1,081 | 1,110 | 1,133 | **5,372** |
| **Asset Disposals** | 0 | 0 | 0 | 0 | 0 | **0** |
| **Redundant Capital** | 0 | 0 | 0 | 0 | 0 | **0** |
| **Indexation** | 407 | 1,066 | 1,717 | 1,129 | 1,154 | **5,473** |
| **Closing Capital Base** | **29,124** | **32,335** | **36,127** | **38,323** | **40,251** | **-** |

In determining its regulatory asset base, CEG advises that consistent with the practice and provisions of the Code, the opening value of the Capital Base at 1 January 2004 reflects:

- The initial Capital Base as determined by the Tribunal as at 1 January 1999.
- Plus actual annual capital expenditure (new facilities investment) that meets the provisions of Section 8.16 of the Code.
- Less allowed annual depreciation of the capital.
- Less Redundant Capital and asset disposals.
- With adjustments for changes in the CPI.

CEG advises that:

- Actual capital expenditures have been used for calendar years 1999 to 2002, and forecast capital expenditure has been used for calendar year 2003 (At the time of submitting the Access Arrangement revision in 2003, CEG actual expenditure was not a full year)
- Indexation of the Capital Base has taken place using the following CPI adjustment factors. These factors are based on the index number for the weighted average of eight capital cities as published by the ABS[17] for years ending September. These factors are listed in Table 6-2, along with the inflation factors as provided by CEG[18].

[17] AAI December 2003 page 26
[18] CEG Email Issue 6.3, 3 August 2004

**Table 6-2 CPI Indexation of Capital Base**

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|
| **CPI** | 1.41% | 3.47% | 5.06% | 3.03% | 2.93% |
| **Inflation Factor, nominal $ to year 2003 $** | 1.1358 | 1.1200 | 1.0824 | 1.0303 | 1.000 |

## 6.2 ACTUAL CAPITAL EXPENDITURE: 1999 TO 2003

CEG actual capital expenditure for the period 1999 to 2003 is detailed in Table 4.1 of the December 2003 AAI. CEG advises[19] that this expenditure is in real $ 2003, not real $ 2003/04 as stated in this AAI.

CEG also advises[20] that it had to correct the allocation of the expenditure for the growth related category and the non system asset/FRC category due to the misallocation of costs between these items in 1999, 2000 and 2002. The corrected expenditure provided by CEG is shown in Table 6-3.

CEG advises that "actual" capital expenditure for the year 2003 is estimated[21] due to actual capital expenditure data for year 2003 not being available at the time of producing the December 2003 Access Arrangement Information. It is still currently not available.

**Table 6-3 New Facilities Investment in the Current Access Arrangement Period (Real $ thousand 2003)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est)[22] | Total |
|---|---|---|---|---|---|---|
| **Asset replacement & refurbishment** | | | | | | |
| **- pipes** | 251 | 373 | 271 | 147 | 250 | **1,292** |
| **- meters** | 295 | 476 | 319 | 136 | 83 | **1,309** |
| **Growth Related** | 1,400 | 1,845 | 1,380 | 1,491 | 1,087 | **7,203** |
| **Non-system assets/ FRC** | 0 | 46 | 383 | 352 | 465 | **1,246** |
| **Southern Gate Station** | 0 | 840 | 1064 | 116 | 23 | **2,043** |
| **Actual Capital Expenditure** | **1,946** | **3,580** | **3,416** | **2,242** | **1,908** | **13,092** |

CEG's expenditure for each category above is being assessed in accordance with Section 8.16 of the Code. Details of the review are provided in the following sections. ECG has also assessed the differences between the actual/forecast expenditure and that allowed by the Tribunal's final decision 1999.

CEG advises that areas and projects where expenditure exceeded forecast included the following:

19 CEG Email, Issue 1.17.2, 10 September 2004
20 CEG Email, Issue 1.10, 13 October 2004
21 CEG Email, Issue 6.8, August 2004
22 CEG estimate in 2003 AAI

- Completion of the Southern gate station, which was originally scheduled to be completed in the forthcoming regulatory period.
- Extension of the Network to Uranquinty, in conjunction with the completion of the Southern gate station.
- Significantly higher than forecast connections to the network.
- Costs associated with the introduction of full retail contestability. This expenditure has been deemed to be prudent by Tribunal following a review by PB Associates.
- Expenditure associated with the Asset Management and Operating Support System (AMOSS).

The need to harness resources and divert expenditure to the areas described above resulted in expenditure on other items including asset renewal and replacement being less than forecast.

As described in Section 1, ECG has carried out this review in real $ 2005/06. Details of the actual capital expenditure converted from real $ 2003 in Table 6-3, to real $ 2005/06, are shown in Table 6-5. The method used to calculate these expenditures is detailed below.

ECG has calculated the actual expenditure amounts for each year in real $ 2005/06 by multiplying the actual expenditure amounts for each year provided in Table 6-3 by the conversion factor for that year.

The conversion factor for each year is calculated by dividing its nominal $ to year 2005/06 $ inflation factor, calculated from the CPI factors provided by the Tribunal in Table 6-4, by its nominal $ to year 2003 $ inflation factor calculated from CPI factors, provided by CEG and given in Table 6-2.

This method was required to eliminate differences in the application of CPI factors provided by CEG and the Tribunal

ECG has calculated the conversion of forecast expenditure amounts from real $ 1999 to real $ 2005/06 by using the inflation factor of 1.2195 derived from data provided by the Tribunal presented in Table 6-4.

The calculations for the various factors are provided in Appendix 3.

**Table 6-4 CPI Factors**

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|
| **CPI** | 1.47% | 4.48% | 4.38% | 3.00% | 2.77% |
| **Inflation Factor, nominal $ to year 2005-06 $** | 1.2195 | 1.1672 | 1.1182 | 1.0856 | 1.0564 |
| **Conversion Factor, 2003 $ to 2005-06 $** | 1.0736 | 1.0422 | 1.0330 | 1.0536 | 1.0564 |

**Table 6-5 New Facilities Investment in the First Access Arrangement Period (Real $ thousand 2005/06)**

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Asset replacement & refurbishment** | | | | | | |
| **- pipes** | 270 | 389 | 280 | 155 | 264 | **1,357** |
| **- meters** | 317 | 496 | 330 | 143 | 88 | **1,373** |
| **Growth Related** | 1,503 | 1,923 | 1,426 | 1,571 | 1,148 | **7,571** |
| **Non-system assets, FRC** | 0 | 48 | 395 | 371 | 491 | **1,305** |
| **Southern Gate Station** | 0 | 875 | 1,099 | 122 | 24 | **2,120** |
| **Total Actual Capital Expenditure** | **2,090** | **3,731** | **3,530** | **2,362** | **2,015** | **13,726** |

## 6.3 ASSET REPLACEMENT & REFURBISHMENT

CEG advises in its Access Arrangement Information (December 2003) that appropriate asset replacement and refurbishment is essential to ensuring the continuing safety and reliability of the Wagga Wagga Gas Distribution Network and minimising asset lifecycle costs. If asset replacement and refurbishment does not occur at appropriate levels there will be increased costs associated with leak repairs, more frequent interruptions and greater levels of Unaccounted for Gas. ECG concurs with this advice.

CEG further advises that asset replacement and refurbishment expenditure includes general replacement and refurbishment of the galvanised steel and cast iron network and the replacement of meters.

### 6.3.1 Derivation of Actual and Forecast Expenditure

The AAI 2003 has not presented the data for replacement/refurbishment and meter change in a similar manner to the Final Decision 1999. This means that to be able to analyse the expenditure for these two categories, ECG has had to derive the data. This section outlines the process ECG has followed to determine the actual expenditure for network replacement/refurbishment and meter change.

Asset replacement and refurbishment capital expenditure data shown in Table 6-6 are excerpts from the Final Decision 1999 and the CEG Access Arrangement Information (December 2003).

**Table 6-6 Replacement/refurbishment Capital Expenditure 1999 to 2003**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| ***Final Decision 1999*** ***(Real $ thousand 1999)*** | | | | | | |
| Replacement/ Refurbishment[23] | 560 | 550 | 599 | 514 | 510 | **2,734** |
| ***CEG Actual/Forecast*** ***(Real $ thousand 2003)*** | | | | | | |
| Replacement/ | 546 | 849 | 590 | 283 | 333 | **2,601** |

[23] Sum of the expenditure for system rehabilitation, Meter change/testing and refurbishment in AAI September 1999 Attachment 4.

| Refurbishment[24] |
|---|

A comparison in real $ 2005/06 between the Final Decision 1999 Replacement and Refurbishment allowable expenditure and the CEG Actual Expenditure for the period 1999 to 2003 is shown in Table 6-7.

**Table 6-7 Replacement/Refurbishment Capital Expenditure 1999 to 2004 (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| ***Final Decision 1999*** | | | | | | |
| Renewal/ Refurbishment | 684 | 671 | 731 | 628 | 623 | 3,337 |
| ***Actual/Forecast*** | | | | | | |
| Renewal/ Refurbishment | 586 | 885 | 609 | 298 | 358 | **2,737** |

As can be seen from the comparison, the actual CEG expenditure on Replacement and Refurbishment was $600,000 (Real 2005/06) or 18% below that of the Final Decision 1999.

CEG advises[25] that the main reason for the underspending was the diversion of resources from replacement/refurbishment works to growth related capital works due to the significant increase in new customer numbers above that allowed for in the current Access Arrangement.

The Final Decision 1999 provided for replacement/refurbishment expenditure in the following three categories:

1. System rehabilitation.
2. Meter change/testing.
3. Refurbishment.

CEG advises that the "system rehabilitation" expenditure is only for the replacement of gas mains only. The "refurbishment" expenditure is for the replacement of gas services which is the branch pipe that extends from the gas mains in the street to into the customer's property. The reasons for splitting mains and services expenditure are unclear to ECG because service refurbishment is an integral part of mains replacement/refurbishment works.

In addition, CEG further advises[26] that in Table 4.1 of the December 2003 AAI, the expenditure on service refurbishment is combined with meter replacement and that an accurate separation of the two is not possible. CEG indicated[27] that to obtain the actual expenditure for meter replacement, the Final Decision 1999 service (refurbishment) allowance shown in Table 6-8 below can be subtracted from this actual combined cost.

ECG has adopted this methodology to obtain the meter change costs. In addition, to be able to assess the mains replacement/refurbishment, ECG has included the Final Decision

[24] Sum of the expenditure for pipes and meters in AAI, December 2003 – Table 4.1
[25] CEG Email, Issue 3.2, 20 October 2004
[26] CEG Email, Issue 3.2, 20 October 2004
[27] CEG Email, Issue 3.2, 20 October 2004

1999 service (refurbishment) allowance in its analysis of mains replacement/refurbishment in Section 6.3.2.

Based on the above, ECG has derived the meter replacement expenditure levels as shown in Table 6-8.

**Table 6-8 Derived Meter Replacement/Service Rehabilitation Costs 1999 to 2003 (Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003* | Total |
|---|---|---|---|---|---|---|
| **AAI 2003 combined services refurbishment & meter change/testing allowance - Actual Expenditure** | 260 | 425 | 295 | 132 | 83 | 1,195 |
| ***Final Decision 1999 Service Refurbishment Allowance*** | *60* | *81* | *84* | *87* | *90* | *402* |
| ***Derived Meter Change/Testing Actual Expenditure*** | *200* | *344* | *211* | *45* | *0* | *800* |
| | | | | | | |
| **Final Decision 1999 Meter Change/testing Allowance** | 200 | 165 | 225 | 137 | 136 | 863 |

*Note: The 2003 Derived Meter/Testing Actual Expenditure (Row 3) is shown as zero as the Final Decision Service Allowance (Row 2) is less than the AAI 2003 combined costs (Row 1).

Table 6-9 converts Table 6-8 data to real $ 2005/06.

**Table 6-9 Meter Replacement/Service Rehabilitation Costs 1999 to 2003 (Real $ thousand 2005/06)**

| Services | 1999 | 2000 | 2001 | 2002 | 2003* | Total |
|---|---|---|---|---|---|---|
| **AAI December 2003 Combined Service Refurbishment & Meter Change/testing Actual Expenditure** | 317 | 496 | 330 | 143 | 88 | 1,374 |
| ***Final Decision 1999 Service Refurbishment Allowance*** | *73* | *94* | *94* | *94* | *94* | *449* |
| ***Derived Meter Change/Testing Actual Expenditure*** | *244* | *402* | *236* | *49* | *0* | *931* |
| | | | | | | |
| **Final Decision 1999 Meter Change/testing Allowance** | 244 | 192 | 252 | 149 | 144 | 980 |

*Note: The 2003 Derived Meter/Testing Actual Expenditure (Row 3) is shown as zero as the Final Decision Service Allowance (Row 2) is less than the AAI 2003 combined costs (Row 1).
The expenditure that ECG has utilised for its analysis is shown in Table 6-10.

**Table 6-10 Derived Asset Replacement Expenditure for 1999 to 2003 (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Derived Actual Expenditure Mains & Services** | 343 | 483 | 374 | 248 | 358 | 1,805 |
| **Derived Actual Expenditure Meter Replacement (Derived from (**Table 6-12**)** | 244 | 402 | 236 | 49 | 0 | **931** |
| **Total Replacement Expenditure** | 587 | 885 | 609 | 297 | 358 | **2,736** |

### 6.3.2 Review of Actual Expenditure - Mains & Services Replacement/ Refurbishment Program

Table 6-11 shows Final Decision 1999 versus Actual Expenditure for mains & services replacement/refurbishment in real $ 2005/06 as derived in Section 6.3.1.

**Table 6-11 Mains & Services replacement/refurbishment for 1999 to 2003 (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999** | 439 | 479 | 479 | 479 | 479 | 2,354 |
| **Actual Expenditure** | 343 | 483 | 374 | 248 | 358 | 1,805 |

No information has been provided by CEG about the risks or impacts on network operational performance that may be associated with its decision to defer planned replacement/refurbishment of its mains and services.

The CEG network in Wagga Wagga contained approximately 182km of galvanised steel and cast iron mains in 2002[28], which is about 30% of the total network. The age of the majority of these mains dates from the 1950's with the last of the cast iron being laid in the early 1990s.

[28] CEG Safety and Operating Plan

During the period from 1999 to 2003, the replacement/refurbishment program renewed 18.797 kilometres of mains for a total expenditure of $1,805,000 (Real $ 2005/06). This equates to an average rehabilitation rate of $96 per metre (Real $ 2005/06).

CEG advises[29] that this work was undertaken via a number of small projects and Business Cases were not required as individual projects were within the local manager authority level of $100,000 designated in CEG's capital approval process. In the absence of an Asset Management Plan it is unclear why all replacement/refurbishment of mains and services involved several small projects. Aggregation would be expected to deliver economies of scale, even for a relatively small network.

CEG advises that the main driver for replacing/refurbishing sections of the galvanised steel and cast iron mains, particularly cast iron, is when leak survey information indicates that replacement/refurbishment is more economical than continued repair. The exception to this is where insufficient capacity exists within the main. Other than this advice, ECG has not been presented with any other information that contributes to justifying the level of replacement/refurbishment in the period 1999 to 2003, eg. Risk analyses, asset condition trend data, frequency of interruption to supply, customer complaints related to supply problems.

Notwithstanding ECG's observations and comments, a prudent network operator would be expected to systematically replace/refurbish aged galvanised steel and cast iron mains. CEG replaced/refurbished 18.797km during the period 1999 to 2003 which represents approximately 10% (or 2% per year) of the remaining length. In the absence of an Asset Management Plan, ECG accepts that CEG's length of replaced/refurbished mains is consistent with a network operator acting prudently in accordance with section 8.16 of the Code for the purpose of determining the level of capital expenditure that meets the Code requirements for the period 1999 to 2003.

As noted earlier in this section, CEG's average replacement/refurbishment rate equates to $96 per metre (Real 2005/06). This is higher than the $76.40 (Nominal) or approximately $79 (Real 2005) achieved by AGLGN in NSW for the period 2000 to 2004[30] and is compatible with the range of $96 to $129 (Real 2005/06) per metre determined by the Essential Services Commission's (ESC's) last Final Determination in Victoria in 2002.

Due to the variables involved (e.g. different economies of scale, reinstatement and traffic management requirements); it is difficult to make a definitive comparison between CEG and the other larger jurisdictions. However there is sufficient information available for ECG to conclude that CEG's average unit rate is within a range that can be considered efficient in terms of meeting Section 8.16 of the Code.

In summary ECG recommends that the actual expenditure of $1,805,000 (Real 2005/06) is used for establishing the opening capital base for the next Access Arrangement Period.
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### 6.3.3 Review of Actual Expenditure - Aged Meter Replacement.

Table 6-12 shows Final Decision 1999 versus Actual Expenditure for aged meter replacement in real $ 2005/06 as derived in Section 6.3.1.

[29] Wagga Meeting - Thursday 29th July, 2004
[30] ECG Review of AGLGN Gas Access Arrangement For IPART, August 2004

**Table 6-12 Derived Aged Meter Replacement Program (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999** | 244 | 192 | 252 | 149 | 144 | 980 |
| **Derived Meter Change/Testing** | 244 | 402 | 236 | 49 | 0 | **931** |

CEG advises[31] that meter replacement occurs when meters reach 15 years of age in order to ensure compliance with the Gas Supply (Gas Meters) Regulation 2002.

The number of aged meter replacements for the period was 4,301[32]. This equates to a unit cost of $216 (Real 2005/06) per aged meter change ($931,000 divided by 4,301). The annual quantity of meters replaced is unknown.

CEG further advises[33] [34] that the meter replacement expenditure covers both residential meters and industrial/commercial meters and due to the low number of industrial and commercial meters involved (estimated to be five per year on average) the overall impact on unit cost is immaterial.

CEG's unit cost of $216 per meter change is considerably higher than ActewAGL's range of $150 - $160 (Real 2005/06) for aged residential meter replacement in Canberra[35] and the rate of $137.50 (Real 2005/06) recommended for AGLGN in NSW[36]. CEG's rate would be expected to be closer to ActewAGL than AGLGN taking into consideration relative economies of scale. Given the cost of a new residential meter is approximately $80 and the time taken to replace a meter is less than one hour, ECG estimates that CEG's unit rate should be in the range of $170 - $180.

ECG recommends a unit rate of $177 (Real 2005/06) which is equal to CEG's forecast for the period 2004 to 2009/10 (refer Section 7.3.2) as the amount that would be invested by a prudent network operator in accordance with Section 8.16 of the Code.

In summary ECG recommends that an expenditure of $761,300 (Real 2005/06) (4,301 meters x $177) is used for establishing the opening capital base for the next Access Arrangement Period. As noted above, the annual quantity of meters replaced is unknown; therefore it is not possible to accurately allocate the recommended expenditure across the years. As an approximation it could be allocated in proportion to the derived annual actual expenditure over the 4 year period 1999 to 2002 (assuming no expenditure in 2003) shown in Table 6-12.

### 6.3.4 Summary of Asset Replacement & Refurbishment

Table 6-13 summarises the ECG recommendation for Asset Replacement and Refurbishment and provides a comparison between the Final Decision 1999 and CEG AAI actual expenditure in real $ 2005/06.

[31] CEG Email, Issue 3.11, 11 August 2004
[32] CEG Email, Issue 3.28.3, 26 November 2004
[33] CEG Email, Issue 3.9, 29 October 2004
[34] CEG Email, Issue 3.13, 12 October 2004
[35] MMA Review of Gas Transportation Charges on the ActewAGL Distribution, June 2004
[36] ECG Review of AGLGN Gas Access Arrangement For IPART, August 2004

**Table 6-13 Comparison of ECG recommendation with Final Decision 1999 and CEG AAI actual expenditure (Real $thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **ECG Recommendation** | 539 | 807 | 563 | 287 | 351 | **2,548** |
| **Final Decision 1999** | 683 | 671 | 731 | 627 | 622 | 3,334 |
| **CEG Actual expenditure** | 586 | 885 | 609 | 298 | 358 | **2,736** |

## 6.4 GROWTH RELATED

To be able to assess the growth expenditure ECG has collated the data from the AAI 2003 and from subsequent data provided by CEG[37 38]. A summary of the expenditure as provided by CEG is shown in Table 6-14. It should be noted that the expenditure provided for year 2003 is forecast, not actual.

**Table 6-14 CEG Capital Expenditure 1999 to 2003 (Real $ thousand, 2003)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Forecast** | | | | | | |
| **Total Volume Customers at year end** | 14,470 | 14,615 | 14,761 | 14,909 | 15,058 | **-** |
| **New Volume Customers** | 143 | 145 | 146 | 148 | 149 | **731** |
| **Connection/Mains ($,000)** | 693 | 724 | 724 | 698 | 632 | **3,472** |
| **Contestable Metering ($,000)** | 290 | 68 | - | - | - | **358** |
| **Glenfield Road ($,000)** | - | - | - | - | - | **-** |
| **Uranquinty ($,000)** | - | - | - | - | - | **-** |
| **Total Capital ($,000)** | **983** | **793** | **724** | **698** | **632** | **3,830** |
| **Actual** | | | | | | |
| **Total Volume Customers** | 14,674 | 15,370 | 16,127 | 16,651 | 16,798 | **-** |
| **New Volume Customers** | 347 | 696 | 757 | 524 | 147 | **2,471** |
| **New Uranquinty (volume) Customers** | No annual customer number is available. | | | | | **181** |
| **New Wagga (volume) Customers** | No annual customer number is available. | | | | | **2,290** |
| **New Industrial & Commercial customers** | 5 | 4 | 14 | 18 | 16 | **57** |
| **New Residential Customers** | 342 | 692 | 743 | 506 | 131 | **2414** |
| **Connection/Mains ($,000)** | 775 | 1845 | 1,006 | 1,372 | 1,087 | **6,085** |
| **Contestable Metering ($,000)** | - | - | - | - | - | **-** |
| **Glenfield Road ($,000)** | 625 | - | - | - | - | **625** |
| **Uranquinty ($,000)** | - | - | 374 | 119 | - | **493** |
| **Total Capital ($,000)** | **1,400** | **1,845** | **1,380** | **1,491** | **1,087** | **7,203** |

[37] AAI, December 2003 - Table 2.3
[38] CEG Email, Issue 1.10, 13 October 2004
CEG Email, Issue 1.13, 10 September 2004
CEG Email, Issue 1.18, 5 November 2004
CEG Email, Issue 1.20, 9 November 2004

**Note:** No information is available on whether the customer numbers above are gross or net of disconnection customer number. ECG has assumed the customer numbers are gross for this review.

The major projects include:

- $625,000 for augmentation of the Wagga Wagga network in Glenfield Road associated with the major Southern Gate Station project.
- $493,000 for supply to Uranquinty.

The expenditure of $6,085,000 is for mains to new customers and associated augmentation projects. The costs include connections to new customers in both Wagga Wagga and Uranquinty. However the mains cost for the Uranquinty project is accounted for separately.

CEG advises there are 2,471 new Volume customers, which is 1,740 more than forecast. There are 2,290 of these in Wagga Wagga and 181 in Uranquinty. In Table 6-14 there are no new industrial and commercial customers shown in 1999. ECG estimates that the 347 new Volume customers in 1999 include 5 Industrial & Commercial Volume customers and 342 Residential Volume customers. This is based on the CEG advice on the actual number of new Industrial & Commercial Volume customers for the period 2000 to 2003[39] as shown in Table 6-14.

For analytical purposes, the capital expenditure from Table 6-14 has been converted to real $ 2005/06 and this is given in Table 6-15. ECG has calculated this by the process described in Section 6.2.

**Table 6-15 CEG Capital Expenditure 1999 to 2003**
**(Real $ thousand 2005/06)**

| | 1999 Actual | 2000 Actual | 2001 Actual | 2002 Actual | 2003 Forecast | Total |
|---|---|---|---|---|---|---|
| **Connection/Mains** | 832 | 1,923 | 1,040 | 1,448 | 1,148 | **6,391** |
| **Contestable Metering** | - | - | - | - | - | **-** |
| **Glenfield Road** | 671 | - | - | - | - | **671** |
| **Uranquinty** | - | - | 386 | 123 | - | **509** |
| **Total Capital** | **1,503** | **1,923** | **1,426** | **1,571** | **1,148** | **7,571** |

### 6.4.1 Glenfield Road Reinforcement

CEG advises[40] that no information is available to verify its estimated expenditure of $671,000 on the major Glenfield Road reinforcement project completed in 1999. This project consisting of 2,800 metres of 200mm steel main was authorised by the Board of Great Southern Energy Gas Networks[41] as Stage 1 of the Southern Gate Station project.

CEG advises that this Stage 1 was required prior to the main project, to ensure adequate system pressure is maintained in affected areas of the Wagga Wagga network during winter 1999. In its capacity analysis report[42], CEG indicated that it had experienced

[39] CEG Email, Issue 1.20, 9 November 2004
[40] CEG Email, Issue 1.10, 13 October 2004
[41] Great Southern Energy Gas Networks is now known as CEG.
[42] CEG Document, Wagga Wagga Natural Gas Distribution Network, 1998 Capacity Analysis

incidents of poor supply over several years. As such ECG concurs that these supply problems needed to be addressed.

In a separate report[43], CEG proposes a major reinforcement based on a new Southern Gate Station and including the Glenfield Rd reinforcement as stage 1, to resolve a number of problems in Wagga Wagga. For reasons outlined in its separate review (Section 6.6), ECG considers this Southern Gate Station project to be prudent.

As the Glenfield Road reinforcement is part of a prudent long term strategy for Wagga Wagga and is an effective project for resolving the immediate supply problems during 1999, ECG considers this to be a prudent project.

ECG calculates the budget cost for the 2,800 meters of 200mm steel main in Glenfield Road to be equivalent to a unit cost of $240[44] per metre (Real 2005/06). ECG appreciates that the unit cost could vary depending on the difficulties encountered in laying gas mains such as rocky terrains and traffic conditions. Based on its experience, ECG believes that the unit cost could range from $150 per metre to $230 per metre. In addition, CEG advises the budgeted cost for 15,000 metres of 200mm steel main for the Southern City Gate station project was $2,200,000 (nominal 1999). CEG also advises that the actual construction cost achieved was less than the budgeted cost. ECG calculates this is equivalent to a unit cost of $180 per metre for 200mm steel main (Real 2005/06).

As such, in the absence of supporting information, ECG considers that the efficient unit cost for Glenfield Road should not exceed $180 per metre.

Using the unit cost of $180 per metre, ECG has calculated the cost for the Glenfield Road project to be $504,000. This has the effect of reducing the CEG allowance for this project by $167,000, from $671,000 to $504,000.

ECG therefore recommends that the expenditure accepted for inclusion in the opening capital base for the next Access Arrangement period for this project is its estimate of $504,000 (Real $ 2005/06). ECG considers this is what would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

### 6.4.2 General Expansion / Reinforcement

As shown in Table 6-15, the expenditure for general expansion/reinforcement for Wagga Wagga is $6,391,000 (Uranquinty has been accounted for separately). To assess this expenditure, ECG has divided the general expansion/ reinforcement expenditure into two categories:

- Expansion mains costs.
- Connection costs include service and meters.

To review the costs for each category, ECG sought the unit cost related to each customer type. However, CEG advises[45] that for the period, 1999 to 2003, it is unable to provide details of actual growth related expenditure by asset type and customer type.

CEG has been able to provide[46] forecast details by asset type for years 2004/05 to 2009/10. The average forecast connection unit cost of each customer type is:

[43] CEG Document 2.38, Wagga Wagga City Natural Gas Augmentation, Southern Gate Project
[44] $671,000 / 2,800metres
[45] CEG Email, Issue 1.10, 13 October 2004
[46] CEG Email, Issue 1.11, 13 October 2004

- $1,458 (real $ 2005/06) per residential volume customer
- $3,064 (real $ 2005/06) per industrial & commercial volume customer.

CEG also advises[47] that its forecast residential connection cost for the period 2004/05 to 2009/10 is less than that allowed for the period, 1999 to 2003 but no details were provided on the difference. In the absence of this information, ECG has assumed that the forecast unit connection cost shown above applies to the current period, 1999 to 2003. ECG has calculated the connection cost for each customer type based on customer numbers given in Table 6-14 to be:

- $3,520,000 (real $ 2005/06) for 2,414 new Residential customer connections[48], based on $1,458 per residential customer.
- $175,000 (real $ 2005/06) for 57 new Industrial & Commercial customer connections[49], based on $3,064 per customer.

The total connection for all customers is therefore $3,695,000 (real $ 2005/06). As no details have been provided for the new expansion mains costs, ECG has calculated the mains costs by subtracting $3,695,000 from the total cost of $6,391,000. The expansion mains costs are therefore $2,696,000 (real $ 2005/06).

#### *6.4.2.1 Expansion Mains Actual Expenditure Analysis*

As discussed in the section above, the total cost for this category derived by ECG is $2,696,000. To review whether the cost complies with the Code, ECG has analysed the cost by considering two factors; the unit cost per metre and the average unit length per customer.

CEG advises[50] that approximately 45,000 metres of expansion mains were laid to supply customers in Wagga Wagga (excluding Uranquinty) during this time. From the total cost of $2,696,000, ECG has calculated the average unit cost of new mains to be $60 per metre.

In addition, as shown in Table 6-14, there were 2,290 new customers in the period, 1999 to 2003; the average unit length is 19.7 metres per customer.

In the cost review[51] carried out for the Independent Competition and Regulatory Commission (ICRC), ECG identified that the unit cost for new customers in Victoria is approximately 20metres per new customer and for Canberra is 26 metres per new customer. Therefore ECG considers the 19.7 metres of main per average customer in Wagga Wagga to be reasonable.

CEG advises[52] the factors contributing to the mains cost in Wagga Wagga include:

- 90 - 95 % of all new mains (excluding the major steel reinforcement projects) use polyethylene pipe
- New mains are from 40mm to 200mm diameter depending on the scope of project.

[47] CEG Email, Issue 1.23, 26 November 2004
[48] Refer Table 6-14
[49] Refer Table 6-14
[50] CEG Email, Issue 1.18, 5 November 2004
[51] MMA Final Report to ICRC; ActewAGL Gas Distribution Network; Section 11.4.2; 28 June 2004
[52] CEG Email, Issue 1.22, 26 November 2004

ECG recognises that the unit cost of the expansion mains is dependent on a number of factors including the location, size and ground condition. ECG believes that the mains cost in Wagga Wagga would be higher than Melbourne, Sydney and Canberra due to economy of scale factors.

In addition, based on its industry experience, ECG believes that the size of mains used for new expansion would vary from 40mm to 110mm and would be in the range of $38 per metre to $110 per metre. The high end of the scale would be in existing built up areas.

From the factors above, ECG estimates that the unit cost for Wagga Wagga would be in the range of $45 to $65 per metre.

Based on its inspection of the Wagga Wagga gas supply area where most new connections are located (i.e. in new subdivisions) and allowing for the above factors, ECG considers that the unit cost for a prudent service provider would be $55 per metre.

Using $55 per metre for 45,000 metres, ECG considers that the efficient cost that would comply with the Code would be $2,475,000.

ECG therefore recommends that the expenditure on expansion mains accepted for inclusion in the opening capital base for the next Access Arrangement period is its estimate of $2,475,000 (real $ 2005/06).

#### *6.4.2.2 Connections Actual Expenditure Analysis*

As discussed in Section 6.4.2, ECG has estimated the total expenditure for this category is $3,695,000. This is based on a cost of $175,000 for industrial and commercial customers[53] (unit cost of $3,064) and $3,520,000 for residential customers (unit cost of $1,458).

The connection costs include two components, the cost for a service and the cost for a meter-regulator. From the cost review carried out for ICRC, ECG has estimated that the average cost per industrial & commercial customer is $1,126 per service and $2,426 per meter-regulator, totalling $3,552 (Real 2003/04). The average cost per residential customer was $659 per service and $180 per meter-regulator, totalling $839 (Real 2003/04).[54]

Whilst it is recognised that the customer type affects the unit cost for industrial and commercial customers, the unit cost in Wagga Wagga for industrial and commercial customers is within the cost from the ICRC work. ECG considers that the unit cost for industrial and commercial customers in Wagga Wagga is efficient. Therefore ECG considers the estimated expenditure of $175,000 for the 57 new Industrial & Commercial customers to be efficient and complies with the Code.

However, the unit connection cost for residential customers in Wagga Wagga is considerably higher than the cost identified in the ICRC study.

As mentioned above, the connection cost consists of two components; a service cost and a meter-regulator cost. As CEG has not provided the cost per service and the cost per meter-regulator, ECG has estimated that the cost per meter-regulator is $200[55]. This means that the average cost per service is $1,258.

[53] CEG Email, Issue 1.11, 13 October 2004

[54] MMA Final Report to ICRC, ActewAGL Gas Distribution Network, Table 11.7, 28 June 2004

[55] $200 is based on the cost of a meter, regulator and associated fittings allowing for a small proportion of larger size meters.

In the AGL total cost study, the service costs vary from an average of $731 per service for individual customers in new subdivisions to $1,305 per service for individual customers in existing built up areas (Real $ 2005/06)[56]. However, ECG expects that residential service cost for CEG in Wagga Wagga to be higher than that for AGL's costs due to the relative economies of scale for CEG as compared to AGL. Whilst it is difficult to be explicit in terms of the cost differential, ECG believes that a reasonable cost difference would be in the order of 10%. Using the AGL cost study, ECG estimates that the cost for CEG could vary from $804 to $1,434.

As the majority of the residential services in Wagga Wagga are in new areas, ECG believes that a weighed average cost per service would be in the order of $950.

ECG therefore estimates the efficient connection unit cost for residential customers is $1,150[57] per customer and the efficient expenditure for 2414 new residential customers is $2,776,000.

ECG therefore considers that the prudent and efficient expenditure on connections for all residential and industrial & commercial volume customers is $2,951,000[58].

ECG therefore recommends that the expenditure on new connections accepted for inclusion in the opening capital base for the next Access Arrangement period is $2,951,000 (Real $ 2005/06). This has the effect of reducing the CEG allowance for these connections by $744,000, from $3,695,000 to $2,951,000.

#### *6.4.2.3 Actual Expenditure Summary*

Based on these analyses, ECG considers that the prudent and efficient expenditure for General Expansion / Augmentation is $5,426,000, consisting of $2,475,000 for mains and $2,951,000 for connections. This has the effect of reducing the allowable expenditure on connections and mains by $965,000, from $6,391,000 to $5,426,000.

Consistent with section 8.16 of the Code, ECG therefore recommends that the General Expansion / Augmentation expenditure accepted for inclusion in the opening capital base for the next Access Arrangement period is its estimate of $5,426,000. ECG considers this is what would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

### 6.4.3 Uranquinty Network Extension

The Uranquinty network extension was not included in the Final Decision 1999. However, following the approval of the Access Arrangement in 1999, CEG reviewed[59] the extension of the network to Uranquinty. CEG said in its AAI 2003 that the project passes the economic feasibility test in the Code, particularly when constructed in conjunction with the Southern Gate Station.

CEG advises[60] that it sought Board approval for this proposal to extend the supply of natural gas to the existing Uranquinty township with about 300 homes. The estimated project cost then was $600,000 (Nominal $ 2000), equivalent to $700,000 (Real $ 2005/06) with about 250 customers expected to connect within five years. The economic

[56] ECG Final Report to IPART, AGLGN, Sections 8.3.2, 8.3.3, 27 August 2004
[57] $950 per service and $200 per meter-regulator
[58] $2,776,000 for residential customers and $175,000 for industrial and commercial customers.
[59] AAI, Section 2.2.1, December 2003
[60] CEG Proposal and Recommendation 2.41, Natural Gas Reticulation of Uranquinty Township

evaluation showed it is forecast to achieve a [Confidential] internal rate of return based on a post tax WACC of 7.52% and a 30-year assessment period.

CEG data summarised in Table 6-15 and Table 6-14, shows the actual expenditure is $509,000 and that 181 customers had connected to gas by year 2003. ECG considers the number of connected customers is consistent with the five-year forecast of 250 customers, and is therefore consistent with the anticipated incremental revenue to be generated by the new facilities.

CEG had not provided details in relation to the facilities that are included in the project. However ECG believes that the total expenditure of $509,000 is consistent with that for a field regulator of $150,000 and mains cost of $359,000 or $1,436[61] per forecast new customer in Uranquinty.

Using the cost of $1,436 per customer and the unit cost of $55 per metre, the average mains extension unit length is 26 metres per customer. This is higher than the average unit length of 19.7[62] metres per customer in Wagga Wagga but consistent with the mains extension unit length of 26 metres per customer in Canberra (refer Section 6.4.2.1). In addition, ECG also recognises that this estimate of 26 metres has been derived from the assumption that the field regulator cost is $150,000. Given the broad assumptions used to analyse the cost of this project, ECG believes that it is likely that the cost of the project could be efficient consistent with the requirements of the Code.

In addition, as the project was justified on a higher budget cost than actual and the project achieved a number of connected customers consistent with the forecast, ECG considers that this project to extend supply to Uranquinty to be what would be expected of a prudent network operator, acting efficiently consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

ECG therefore recommends that the actual cost of $509,000 be used for the purposes of establishing the opening capital base for the next Access Arrangement period.

### 6.4.4 Summary

A summary of the recommended growth related expenditure to be accepted for inclusion in the capital base for the current period and in the opening capital base for the period is given in Table 6-16. The connection / mains expenditure in each year has been calculated by reducing the CEG estimates for each year in proportion to the total reduction in allowance for the period.

**Table 6-16 CEG Recommended Growth Capital Expenditure (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | TOTAL |
|---|---|---|---|---|---|---|
| **Connection/Mains** | 706 | 1,633 | 883 | 1,230 | 974 | **5,426** |
| **Glenfield Road** | 504 | | | | | **504** |
| **Uranquinty** | | | 386 | 123 | | **509** |
| **Total Growth Capital** | **1,210** | **1,633** | **1,269** | **1,353** | **974** | **6,439** |

Expressed in $ nominal, the recommended growth capital expenditure is as shown in Table 6-17.

[61] $359,000 divided by 250 customers.
[62] Refer section 6.4.2.1

**Table 6-17 CEG Recommended Growth Capital Expenditure (Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | TOTAL |
|---|---|---|---|---|---|---|
| **Total Growth Capital** | **992** | **1,399** | **1,135** | **1,246** | **922** | **5,614** |

## 6.5 NON SYSTEM ASSETS, FRC

As presented in the Access Arrangement Information[63], CEG actual expenditure for the non-system assets was substantially more than that allowed under the Final Decision 1999[64] as shown in Table 6-18. Note: the Final Decision 1999 listed non system assets as "Other Items".

**Table 6-18 Non System Asset Replacement Program**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999 Non System Assets[65] (Real $ thousand 1999)** | 16 | 16 | 16 | 16 | 16 | **78** |
| **Actual Expenditure Non System Assets (Real $ thousand 2003)** | 123 | 139 | 383 | 435 | 465 | **1,545** |

Table 6-18 has been converted to real $ 2005/06 as shown in Table 6-19

**Table 6-19 Non System Asset Replacement Program (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999 Non System Assets** | 19 | 19 | 19 | 19 | 19 | **95** |
| **Actual Expenditure Non System Assets** | 132 | 145 | 396 | 458 | 491 | **1,622** |

Non System Assets in the Final Decision 1999[66] included allowances for computer software, computer hardware, telephones, office furniture and equipment, other and instruments.

In the reported expenditure for the period from 1999 to 2003, CEG has included expenditure for Full Retail Contestability (FRC), SCADA/telemetry and an IT project 'Asset Management and Operating Support System' (AMOSS). No expenditure for computer

[63] AAI, December 2003 – Table 4.1
[64] AA – Attachment 4 – Five Year
[65] Listed as Other Items
[66] AA – Attachment 4 – Five Year

hardware, telephones, office furniture and equipment, other and instruments as allowed for in the Final Decision has been included.

For the purposes of this report, the Final Decision 1999 expenditure allowance for telemetry (listed under Distribution System) has been added to the non system assets as shown in Table 6-20. Table 6-20 is produced to facilitate comparative analysis because the data as presented in the Final decision 1999 and the AAI 2003 refer to different asset groups.

**Table 6-20 Non System Assets Replacement Program plus Telemetry**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999 Non System Assets** **(Real $ thousand 1999)** | 16 | 16 | 16 | 16 | 16 | **78** |
| **Final Decision 1999 Telemetry** **(Real $ thousand 1999)** | 60 | 100 | 20 | 20 | 20 | **220** |
| **Final Decision 1999 Total** | **76** | **116** | **36** | **36** | **36** | **298** |
| **Actual Expenditure - Non System Assets** **(Real $ thousand 2003)** | 123 | 139 | 383 | 435 | 465 | **1,545** |

Table 6-20 has been converted to real $ 2005/06 as shown in Table 6-21.

**Table 6-21 Non System Assets Replacement Program plus Telemetry (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999 Non System Assets** | 19 | 19 | 19 | 19 | 19 | **95** |
| **Final Decision 1999 Telemetry** | 73 | 122 | 24 | 24 | 24 | **268** |
| **Final Decision 1999 Total** | 92 | 141 | 43 | 43 | 43 | **363** |
| **Actual Expenditure - Non System Assets** | 132 | 145 | 396 | 458 | 491 | **1,622** |

After further investigation into the details of the non-system capital expenditure components, CEG[67] found that expenditure relating to growth capital expenditure had been incorrectly allocated to non-system assets.

Table 6-22 shows the revised data for the total non system asset expenditure incurred by CEG.

**Table 6-22 Adjusted Expenditure for Non System Asset Replacement Program**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|

[67] CEG Email, Issue 4.1, 13 October 2004

| | | | | | (est) | |
|---|---|---|---|---|---|---|
| **Final Decision 1999**[68] **Non System Assets** **(Real $ thousand 1999)** | 76 | 116 | 36 | 36 | 36 | **298** |
| **Actual Expenditure**[69] **Non System Assets** **(Real $ thousand 2003)** | 0 | 46 | 383 | 353 | 465 | **1,246** |

**Table 6-1 has been converted to real $ 2005/06 as shown in**
Table 6-23.

**Table 6-23 Adjusted Actual Expenditure for Non System Asset Replacement Program (Real $ thousands 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Final Decision 1999, Non-System Assets** | 92 | 141 | 43 | 43 | 43 | **363** |
| **Actual Expenditure, Non-System Assets** | 0 | 48 | 395 | 371 | 491 | **1,305** |

### 6.5.1 Review of Non System Assets Expenditure

CEG's breakdown of actual non-system asset expenditure[70] shown in Table 6-24 indicates that it relates to three categories i.e. FRC, Telemetry/SCADA system and to the AMOSS Project. The total expenditure is $317,000 less than the $1,622,000 AAI amount shown in Table 6-21 due to corrections as notified by CEG in Email Issue 4.1 and as explained in section 6.5.

**Table 6-24 Cost Breakdown for Actual Non System Asset Replacement Program (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **FRC** | 0 | 0 | 258 | 250 | 244 | **752** |
| **Telemetry/SCADA Project** | 0 | 48 | 137 | 121 | 0 | **306** |
| **AMOSS Project - Initial Phase** | 0 | 0 | 0 | 0 | 247 | **247** |
| **TOTAL** | **0** | **48** | **395** | **371** | **491** | **1,305** |

FRC expenditure is reviewed separately in Section 6.5.2. The remaining non-system expenditure for Telemetry/SCADA and AMOSS totals $553,000 (Real 2005/06). This sum is substantially more than the $363,000 (Real 2005/06) allowed in the Final Decision 1999.

The AMOSS Project[71] refers to Country Energy's Asset Management and Operating Support System. The core components of AMOSS are a works and asset management system and the Small World graphical information system, as advised in email response to

[68] AA – Attachment 4 – Five Year
[69] CEG Email, Issue 4.1, 13 October 2004
[70] CEG Email, Issue 4.1, 13 October 2004
[71] CEG Email, Issue 4.1, 13 October 2004

Issue 4.1. Other than this advice, ECG has not been presented with any further information on either the SCADA/Telemetry or AMOSS system expenditure even though scope of work and/or justification for the expenditure documentation was requested.

Based on ECG's industry knowledge, it is necessary in today's regulatory and gas market environment for prudent network operators to invest in integrated asset management information systems such as AMOSS so that they can effectively and efficiently manage the construction, operation and maintenance of their assets. Asset management systems are required to interface electronically with retailers for work management, market system and billing purposes. They are also used to generate management and regulatory reports.

It is understood that the actual AMOSS expenditure of $247,000 (Real 2005/06) is CEG's Wagga Wagga share of the corporate Country Energy (CE) allocation for the initial phase. It is unclear what the initial phase covers and no Business Case has been presented for ECG to review. Given the level of actual expenditure involved and ECG's knowledge of what much larger gas distributors' systems cost, ECG believes that the cost would be equivalent to implementing a basic asset management system.

Based on this assumption, ECG considers that expenditure of $247,000 (real 2005/06) in the period 1999-2003 to be representative of the costs that would be incurred by a prudent network operator, acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

The actual expenditure of $306,000 (Real 2005/06) for the SCADA/telemetry is marginally higher than that allowed by the Final Decision 1999. Based on the assumption that the expenditure was for the purposes of up-grading/replacing gas pressure control/monitoring facilities at several sites, ECG considers the costs as what would be expected over the five year period of a prudent operator in accordance with the Code.

For the purposes of establishing the opening capital base for the next Access Arrangement Period, ECG accepts the expenditure of $553,000 (Real 2005/06) as advised by CEG and recommends that this sum be included.

### 6.5.2 Full Retail Contestability

Expenditure for Full Retail Contestability (FRC) was included in the AAI submission in the Non System Assets expenditure and CEG advises that the FRC expenditure totalled $752,000 (Real 2005/06) over the years from 2001 to 2003.

It should be noted that the figure included for FRC for 2003 is forecast expenditure as CEG have not been able to supply the actual expenditure for that year.

In a confidential report prepared by PB Associates in December 2002 for IPART, PB Associates "recommended accepting the cost put forward in the Country Energy gas network and retail template as prudent and incremental to FRC". In a letter to CEG, dated 10 July 2002, the Tribunal agreed that all of these costs were reasonable costs associated with the introduction of contestability. As advised by the Tribunal, the network component was $870,134 (Nominal)[72]. This consisted of $59,634 in 2000/01 and $810,500 in 2001/02; the conversion of these nominal dollars gives $961,133 (Real 2005/06).

[72] The $870,134 consists of $59,634 in 2000/01 and $810,500 in 2001/02. To convert to 2005/06 apply an inflation factor of 1.014 to the 2000-01 figure to bring it to a real calendar 2001 value and then use our 2001 factor of 1.1182 to bring it to real 2005-06 terms. ie total factor of 1.1339.
For the 2001-02 number the factor is 1.0155 by our 2002 number of 1.0856 to give a total factor of 1.1024.
The half year adjustments are the average of the CPI figures in the second halves of 2001 and 2002 respectively.
2001 Q3 2.5

This compares favourably with CEG's actual expenditure of $752,000 (Real 2005/06).

Given that the actual expenditure is well below the level that was independently assessed as 'prudent and incremental to FRC' by PB Associates and accepted as such by the Tribunal, ECG considers that the actual expenditure is consistent with a network operator acting efficiently and in accordance with the requirements of Section 8.16 of the Code.

ECG therefore recommends the expenditure on FRC of $752,000 (Real 2005/06) be accepted for inclusion in the opening capital base for the next Access Arrangement Period.

### 6.5.3 Summary of Non System Assets Actual Expenditure

Table 6-25 summarises the ECG recommendation for Non System Assets and provides a comparison to both the Final Decision 1999 and CEG AAI actual expenditure in real $ 2005/06.

**Table 6-25 Comparison of ECG recommendation with Final Decision 1999 and CEG AAI actual expenditure**
**(Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **ECG Recommendation including FRC** | 0 | 48 | 395 | 371 | 491 | **1,305** |
| **Final Decision 1999** | 92 | 141 | 43 | 43 | 43 | **363** |
| **CEG Actual expenditure including FRC** | 0 | 48 | 395 | 371 | 491 | **1,305** |

## 6.6 SOUTHERN GATE STATION

In section 2.2.1 in the AAI, December 2003, CEG states that this project originally scheduled to be completed in the forthcoming regulatory period was brought forward (commenced in year 2000) to:

- Resolve pressure/supply problems in the southern areas of the Network, thus improving the standard of service to many customers.
- Prevent a substantial disruption to supply during major repairs to the Murrumbidgee River rail bridge, which would cause the gas main located on this bridge to be unavailable for supply during the repair period. The Rail Infrastructure Corporation has advised CEG these repairs are necessary and are anticipated to occur in 2005.
- Improve security of supply to Wagga Wagga.

In the Final Decision 1999, the Tribunal acknowledged that the existing Wagga Wagga distribution system is at capacity and is unable to meet current and forecast peak flow rates. The Tribunal determined that whilst the Uranquinty option (costing $4,000,000 nominal) will meet the capacity requirements, the preferred option (Southern Gate Station)

2001 Q4 3.1
2002 Q3 3.2
2002 Q4 3.0

is to loop the existing Wagga Wagga mains over a period of 10 years at a cost of $1,800,000 (Nominal). ECG calculates these costs are equivalent to $5,000,000 and $2,250,000 respectively expressed as real $ 2005/06.

The Tribunal therefore allocated sufficient funds in the Final Decision 1999 for the looping of the existing mains instead of the Southern Gate station. However, this does not preclude CEG from proceeding with the Southern Gate station subject to its own finance.

To assist in its understanding of the issue that the project is trying to address, ECG sought background information from CEG. CEG advises[73] that this Southern Gate Station project was selected from a number of alternatives because it provides additional benefits of increased supply security, a higher level of capacity reinforcement and extension of service access to customers in South Wagga Wagga. CEG also advises that the looping alternative for which funding was allowed in the Final Decision 1999 provides, and states: "only marginal cost savings for likely actual costs of works for a similar performance outcome.

CEG believes that the option to do nothing was high risk due to the possibility of widespread outages from loss of supply at times of peak load. CEG advises that the problem was due to:

- A number of incidents of poor supply occurred over several years.
- Network analysis conducted by an independent consultant[74] confirms that the existing network capacity in 1998 was close to the peak demand of 19000 cubic metres per hour.

Given the above circumstances, ECG concurs with the need to develop a solution for the problems. However, the issue still remains why CEG decided to adopt the Southern Gate option instead of the least cost solution of Looping.

CEG advises[75] [76] it decided to proceed with the Southern City Gate option during this Access Arrangement period for the following reasons:

- CEG was advised by the Rail Infrastructure Corporation that major repairs to the Murrumbidgee rail bridge are anticipated to occur in 2005. This would make the major supply main to Wagga Wagga which is located on this bridge unavailable during the repair period. Major supply disruption would occur unless a new supply main across the river or an alternative source of gas south of the river is provided. The Southern Gate Station provides an alternative source of gas south of the river.
- The actual growth rate in Wagga has been much higher than forecast increasing the rate at which reinforcement is required.
- Significant growth continues to occur in southern Wagga, causing supply difficulties in this area.
- It provides better supply access than the Looping option for developments in South Wagga.
- It provides additional security of supply to the whole Wagga Wagga network.

73 Year 2000 Report, Wagga Wagga City Natural Gas Network Augmentation, Southern Gate Project
74 Review of the Optimised Replacement Cost of the Natural Gas Distribution Network in Wagga Wagga, Kinhill Pty Ltd, 30 June 1998.
75 CEG Proposal and Recommendation 2.38, Wagga Wagga City Gas Network Augmentation, Southern Gate Project.
76 AAI, Section 2.2.1, December 2003.

- It could be implemented for lower than previously estimated costs, by progressing in conjunction with the approved major Visy pipeline project and achieving savings in the provision of design, materials procurement and construction services

- It provides a greater increase in capacity than the Looping option.

- It is only marginally more expensive than the Looping option

Whilst ECG has not sighted any report quantifying the benefits of the Southern Gate Station option versus the Looping option, ECG acknowledges that the key factors that would support making the decision on proceeding with the Southern Gate Station are:

- Reinforcement of the Wagga Wagga gas supply network is required.

- The rail bridge across the Murrumbidgee River is in poor condition.

- Substantial disruption to gas supply would occur if the supply main on the rail bridge is unavailable during the peak demand season.

- Provision of the Southern Gate Station and associated new supply main would avoid supply disruption due to the unavailability of the present main located on the Murrumbidgee rail bridge. It would also avoid the expense of a new supply main across the river to be constructed prior to repair of the rail bridge.

- Provision of a Southern Gate Station would substantially increase the security of supply to Wagga Wagga.

- The actual growth rate has been has been significantly higher than that forecast at the time of preparing the current Access Arrangement.

- Significant growth has occurred in southern Wagga Wagga since the time of .preparing the current Access Arrangement

- The higher than forecast growth and the location of this growth in Southern Wagga Wagga, significantly increase the justification for the Southern Gate Station option relative to the Looping option.

- The looping option would not have achieved equivalent cost benefits, as it was planned to be staged over a number of years and would not have coincided with the major Visy pipeline project.

ECG believes that the strongest argument to proceed with the Southern Gate Station is the repair of the bridge across the Murrumbidgee river which would result in the supply main on the bridge not being available. In addition, the cost savings achieved during construction, as outlined below, would reduce the gap between the advantages of the Looping versus the Southern Gate Station.

From the above analysis and recognising that there is no report quantifying the benefits of Southern Gate Station project, ECG considers that the decision to proceed with the Southern Gate Station is most likely to be made by a prudent service provider acting efficiently.

The actual expenditure shown above in Table 6-5 is $2,120,000 (Real 2005/06) for the project consisting of the Southern Gate Station, 15,000 metres of 200mm steel pipeline and control/monitoring facilities. This expenditure is substantially lower than the budgeted amount of $3,500,000. CEG has provided a report compiled by the Network Development Manager[77] which provides the budget costs for the gas infrastructure.

ECG therefore considers that the actual cost of $2,120,000 meets the requirements of the Code.

ECG therefore recommends that the actual costs of $2,120,000 be used for the purposes of establishing the opening capital base for the 2005-2010 Access Arrangement period.

The recommended Southern Gate station capital expenditure is as shown in Table 6-26.

**Table 6-26 CEG Recommended Southern Gate Station Capital Expenditure (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | TOTAL |
|---|---|---|---|---|---|---|
| **Total Growth Capital** | **0** | **875** | **1,099** | **122** | **24** | **2,120** |

Expressed in nominal $, the recommended Southern Gate station capital expenditure is as shown in Table 6-27.

**Table 6-27 CEG Recommended Southern Gate Station Capital Expenditure (Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | TOTAL |
|---|---|---|---|---|---|---|
| **Total Growth Capital** | **0** | **750** | **983** | **112** | **23** | **1,868** |

## 6.7 REDUNDANT CAPITAL & ASSET DISPOSALS

CEG advises that the level of redundant capital and asset disposals during the current period was not material[78]. Mains and services that were rehabilitated are either retained on the books as conduits for new inserted assets or have been fully depreciated. Meters were only replaced at the end of their economic lives and therefore also had no book value.

ECG recommends the acceptance of CEG's position on Disposals.

## 6.8 CAPITAL CONTRIBUTION

Sections 8.23 and 8.24 of the National Gas Access Code allow for capital contributions by customers and the regulatory capital base excludes these capital contributions from the expenditure required in providing gas supply. No allowance was made for such capital contributions in the current Access Arrangement period[79].

CEG advises [80] that contributions have been made, but are excluded from the Capital Base. The actual amounts for years 1999-2002 and the forecast amount for year 2003, are given in nominal $ in Table 6-28.

[77] Wagga Wagga Cit Natural Gas Network Augmentation – Southern Gate Project ( undated)
[78] CEG response to Issue 3.7, Wagga meeting, 29th July, 2004
[79] AAI, September 1999
[80] CEG Email, Issue 1.17.3, 10 September 2004

**Table 6-28 Capital Contributions 1999 to 2003**
**(Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | TOTAL |
|---|---|---|---|---|---|---|
| **Capital Contributions** | 0 | 0 | 0 | 0 | 40 | **40** |

The contribution in 2003 is about 4% of forecast growth capital and ECG considers based on its experience that this level, which is higher than known to be achieved elsewhere in the industry, is efficient. Therefore ECG considers this capital contribution to be what would be expected from a prudent operator acting efficiently, consistent with good industry practice and in accordance with the requirements of Section 8.16 of the code.

ECG therefore recommends the capital contribution of $40,000 (Nominal) is accepted for inclusion in the calculation of the Regulatory Capital Base.

## 6.9 RECOMMENDATIONS FOR CAPITAL EXPENDITURE 1999 TO 2003

It is proposed that the capital expenditure from 1999 to 2003 shown in Table 6-30 be allowed for inclusion in the opening capital base for the Access Arrangement period from 2005 to 2010. Note that for purposes of comparison with the CEG proposal, system reinforcement and renewal/replacement items have been aggregated to a single category.

**Table 6-29 Recommended Capital Expenditure 1999 to 2003**
**(Real $ thousand 2005/06)**

| Calendar years | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| Asset Replacement and Refurbishment | 542 | 812 | 566 | 288 | 358 | 2,566 |
| Growth Related | 1,210 | 1,633 | 1,269 | 1,353 | 974 | 6,439 |
| Non System Assets, FRC | 0 | 48 | 396 | 371 | 491 | 1,306 |
| Southern Gate Station | 0 | 875 | 1,099 | 122 | 24 | 2,120 |
| **Total** | **1,752** | **3,368** | **3,330** | **2,134** | **1,847** | **12,431** |

The above recommended expenditure has been converted to nominal $ for inclusion into the capital base as shown in Table 6-30.

**Table 6-30 Recommended Capital Expenditure 1999 to 2003**
**(Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| Asset Replacement and Refurbishment | 444 | 695 | 506 | 266 | 339 | 2,251 |
| Growth Related | 992 | 1,399 | 1,135 | 1,246 | 922 | 5,694 |
| Non System Assets, FRC | 0 | 41 | 353 | 343 | 465 | 1,202 |
| Southern Gate Station | 0 | 750 | 983 | 112 | 23 | 1,868 |
| **Total** | **1,436** | **2,885** | **2,977** | **1,967** | **1,749** | **9,813** |

# 7. CAPITAL EXPENDITURE FORECAST 2004 TO 2010

## 7.1 CEG FORECAST CAPITAL BASE

Section 8.20 of the Code enables reference tariffs to be determined on the basis of forecast capital expenditure, provided that the capital expenditure is reasonably expected to pass the requirements of Section 8.16 of the Code.

Section 8.32 enables reference tariffs to reflect forecast depreciation over the Access Arrangement period. Section 8.33 requires depreciation to reflect the economic life of the asset group in question.

The Code does not specifically outline the approach that has to be adopted to determine the efficient cost for a level of service. As such, ECG proposes to assess the capital costs as outlined in Section 6.

CEG sets out its calculation of the Regulatory Capital Base for the period from January 2004 to June 2010 in the Access Arrangement Information[81] . However, CEG has since advised that there are minor changes to some of the items (e.g. depreciation in 2004) in the Capital Base and that the revised Regulatory Capital Base for this period is as shown in Table 7-1. The Table 7-1 includes the revised forecast for calendar year 2004[82] and the revised forecast for the period Jan 2005 to June 2010[83].

**Table 7-1 Projected Capital Base (Nominal $ thousand)**

| Financial Year | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Opening Capital Base** | **40,251** | **42,217** | **42,801** | **44,029** | **45,323** | **46,460** | **47,547** | |
| **Capital Expenditure** | 1893 | 904 | 1,855 | 2,012 | 1,953 | 2,006 | 2,210 | **12,833** |
| **Depreciation** | 1,155 | 800 | 1,600 | 1,720 | 1,846 | 1,975 | 2,110 | **11,206** |
| **Asset Sales** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Redundant Capital** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Indexation** | 921 | 480 | 973 | 1,002 | 1,030 | 1,056 | 1,082 | **6,544** |
| **Closing Capital Base** | **41,910** | **42,801** | **44,029** | **45,323** | **46,460** | **47,547** | **48,729** | |

ECG notes that there is an anomaly between the Closing Capital Base for Calendar year 2004 ($41,911,000) and the Opening Capital Base for year 2005 ($42,217,000). CEG has advised that this due to CEG revising its costs for 2004 but not carrying forward the totals from the closing capital base for 2004 to the opening capital base for 2005.

ECG advises the corrected values for the CEG projected capital base are as given in Table 7-2.

[81] AAI, Table 4.3 & 4.10, 31 Dec 2003
[82] CEG Email, Issue 6.4, 3 August 2004
[83] CEG Email, Issue 6.7, 3 August 2004

**Table 7-2 Projected Capital Base**
**(Nominal $ thousand)**

| Financial Year | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Opening Capital Base** | **40,251** | **41,911** | **42,495** | **43,723** | **45,017** | **46,154** | **47,241** | |
| **Capital Expenditure** | 1893 | 904 | 1,855 | 2,012 | 1,953 | 2,006 | 2,210 | **12,833** |
| **Depreciation** | 1,155 | 800 | 1,600 | 1,720 | 1,846 | 1,975 | 2,110 | **11,206** |
| **Asset Sales** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Redundant Capital** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Indexation** | 921 | 480 | 973 | 1,002 | 1,030 | 1,056 | 1,082 | **6,544** |
| **Closing Capital Base** | **41,910** | **42,495** | **43,723** | **45,017** | **46,154** | **47,241** | **48,423** | |

## 7.2 FORECAST CAPITAL EXPENDITURE

The forecast capital expenditure shown in Table 7-1 in nominal $ for calendar year 2004[84]and for the period January 2005 to June 2010 [85] is further detailed in Table 7-3. CEG has advised that its data in Table 4.5 of the AAI is in nominal $, not $ real 2003/04 as stated, and that this also applies for the year 2004 data shown in Table 4.1 of the 2003 AAI.

CEG advises that for 2004 in Table 4.1 in the AAI, it incorrectly allocated $65,000 to "Non system assets/FRC"[86] instead of to "Growth related" [87] category. This means that the correct value for "Non system assets/FRC" is $259,000 ($324,000 in the AAI) and "Growth related" is $817,000 ($752,000 in the AAI). These corrected values are shown in Table 7-3.

**Table 7-3 Forecast New Facilities Investment**
**(Nominal $ thousand)**

| Financial Year | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Mains Rehabilitation** | 734 | 310 | 603 | 775 | 656 | 679 | 792 | **4,549** |
| **Meter Replacement** | 82 | 42 | 91 | 106 | 159 | 203 | 214 | **897** |
| **Growth Related** | 817 | 422 | 896 | 861 | 862 | 842 | 915 | **5,615** |
| **Non-system assets / FRC** | 259 | 129 | 264 | 270 | 276 | 282 | 289 | **1,769** |
| **Total** | **1,893** | **904** | **1,855** | **2,012** | **1,953** | **2,006** | **2,210** | **12,833** |

[84] CEG Email, Issue 6.3, 3 August 2004
[85] AAI, Table 4.5, December 2003 and Issue 1.17.1, 10 September 2004
[86] CEG Email, Issue 4.1, 13 October 2004
[87] CEG Email, Issue 1.10, 13 October 2004

In accordance with Section 8.16 of the Code, ECG has assessed the capital expenditure for each of the three CEG expenditure categories:

- Asset replacement and refurbishment.
- Growth related.
- Non system assets / FRC.

For analytical purposes, the capital expenditure amounts have been converted to real $ 2005/06 and this is given in Table 7-4. ECG has calculated this by using the CPI factors advised by the Tribunal[88] and given in Table 7-5.

**Table 7-4 Forecast New Facilities Investment (Real $ thousand, 2005/06)**

| Financial Year | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Mains Rehabilitation** | 759 | 315 | 603 | 758 | 628 | 636 | 725 | **4,423** |
| **Meter Replacement** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **860** |
| **Growth Related** | 844 | 428 | 896 | 842 | 825 | 788 | 838 | **5,462** |
| **Non-system assets** | 268 | 131 | 264 | 264 | 264 | 264 | 265 | **1,720** |
| **Total** | **1,955** | **917** | **1,854** | **1,968** | **1,869** | **1,878** | **2,024** | **12,465** |

**Table 7-5 CPI Factors**

| Calendar Year | 2004 | Jan – June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 |
|---|---|---|---|---|---|---|---|
| **CPI** | 2.22% | 1.10% | 2.22% | 2.22% | 2.22% | 2.22% | 2.22% |

## 7.3 ASSET REPLACEMENT & REFURBISHMENT

Table 7-6 below comprises excerpts from the AAI December 2003 as follows:

- 2004 forecast expenditure sourced from Table 4.1.
- January 2005 to 2009/10 forecast asset replacement refurbishment sourced from Table 4.5[89].

[88] IPART Email, 27 September 2004
[89] AAI, December 2003 - Table 4.5

**Table 7-6 Replacement/Refurbishment Forecast Capital Expenditure 2004 to 2009-2010 (Nominal $ thousand)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Mains replacement/ refurbishment**** | 734 | 310 | 603 | 775 | 656 | 679 | 792 | **4,549** |
| **Meter replacement** | 82 | 42 | 91 | 106 | 159 | 203 | 214 | **897** |
| **Total Replacement & Refurbishment.** | 816 | 352 | 694 | 881 | 815 | 882 | 1,006 | **5,446** |

**Includes service renewal/refurbishment.

Table 7-7 shows the asset replacement and refurbishment expenditure in real $ 2005/06.

**Table 7-7 Replacement/Refurbishment Forecast Capital Expenditure 2004 to 2009-2010 (Real $ thousand 2005/06)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Mains replacement/ refurbishment**** | 759 | 315 | 603 | 758 | 628 | 636 | 725 | **4,423** |
| **Meter replacement** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **861** |
| **Total Replacement & Refurbishment.** | **843** | **357** | **694** | **862** | **780** | **826** | **921** | **5,284** |

**Includes service renewal/refurbishment.

CEG advises[90] the majority of the galvanised steel network was constructed between 1950 and 1980 and it proposes to replace 2.5% of the network each year over the forthcoming regulatory period. The last of the cast iron mains were laid in the early 1990s. A section of cast iron will be replaced primarily where leak survey information indicates it is prudent to replace a section of main compared to repairing individual leaks, or where insufficient capacity on the main is available.

CEG further advises[91] that its meter replacement costs are based on the meter replacement quantities set out in Table 7-8. Replacement occurs when the meters reach 15 years of age in order to ensure compliance with the Gas Supply (Gas Meters) Regulation 2002.

[90] AAI, Section 4.2.1, December 2003
[91] AAI, Section 4.2.1, December 2003

**Table 7-8 Forecast Quantity of Meter Replacements 2004 to 2009-2010**[92]

| | 2004* | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Meter replacement Quantities** | 325 | 251 | 533 | 609 | 885 | 1,107 | 1,160 | **4,870** |

* The quantity of meter replacements for 2004 has been derived from year 14 of the CEG Wagga Wagga Meter Population Age Chart dated 2003.

### 7.3.1 Review of Forecast Expenditure – Mains & Services Replacement/ Refurbishment

Forecast expenditure in real $ 2005/06 from Section 7.3 is shown in Table 7-7. Forecast mains replacement/refurbishment quantities associated with this expenditure are shown in Table 7-9.

**Table 7-9 Forecast Replacement Quantities for Galvanised Steel and Cast Iron Pipe**

| Quantities (Metres) | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Galvanised Steel**[93] | 2,983 | 1,642 | 3,434 | 3,730 | 4,009 | 4,265 | 4,509 | **24,571** |
| **Cast Iron**[94] | 3,294 | 392 | 1,489 | 2,521 | 1,112 | 924 | 1,501 | **11,233** |
| **Total** | **6,277** | **2,034** | **4,923** | **6,251** | **5,121** | **5,189** | **6,010** | **35,804** |

The remaining length of galvanised steel in the Wagga Wagga network is in the order of 140km. The forecast replacement/refurbishment quantities of galvanised steel are those recommended in a report entitled "A Report on the Replacement of Aging Galvanised Steel Pipe in Country Energy's Wagga Gas Network" by Country Energy's Network Regulatory Strategist. The Report is undated but its focus is on the years 2004-2010 and beyond. Statistical theory is used to generate a replacement programme.

The Report concluded is "Given the prospect of increasing rates of failure of this class of asset as it ages it is strongly recommended that Country Energy commence as soon as possible a comprehensive replacement programme that would smooth out the peaks in replacement over the next 40 years i.e. to replace at a rate of 2.5% pa so as to minimise price impacts on customers moving forward". ECG concurs with this conclusion and accepts that the recommended rate of galvanised steel replacement/refurbishment provides a reasonable basis for forecasting purposes.

ECG has not been provided with any similar studies pertaining to the replacement/refurbishment of the remaining 44km of cast iron mains. CEG's best available

[92] AAI, December 2003 - Table 4.6
[93] Report (undated) on the Replacement of Aging Galvanised Steel Pipe in Country Energy's Wagga Gas Network.
[94] CEG Email, Issue 3.24, 4 November 2004 & CEG Email, Issue 3.30, 9 November 2004

advice[95] is that a section of cast iron will be replaced primarily where leak survey information indicates it is prudent to replace a section of main compared to repairing individual leaks or where insufficient capacity on the main is available. As noted in Section 6.3.2 ECG has not been presented with any other information that contributes to justifying the level of replacement/refurbishment, eg. Risk analyses, asset condition trend data, frequency of interruption to supply, customer complaints related to supply problems.

The forecast 35,804m (total for galvanised steel and cast iron) or 5,510m/year average over 6.5 years is considerably higher than the 18,797m or 3,759m/year average over the previous 5 year period (galvanised steel and cast iron split unknown).

CEG has been unable to provide any information relating to the condition of the remaining cast iron, including any asset condition trend data eg. "moving average" of surveyed leaks/km of mains. However, ECG believes a prudent operator would be expected to replace/refurbish all its cast iron mains within the next 30-40 years and this equates to approximately 6,000m over 6.5 years (approximately 2% pa applied to the 44km of cast iron pipe remaining) or say 1,000m for each of the full forecast years and 500m for January-June 2005.

Based on the above, ECG's recommended forecast quantities are shown in Table 7-10.

**Table 7-10 Recommended Replacement Quantities for Galvanised Steel and Cast Iron Pipe**

| Quantities Metres. | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Galvanised Steel** | 2,983 | 1,642 | 3,434 | 3,730 | 4,009 | 4,265 | 4,509 | **24,572** |
| **Cast Iron** | 1,000 | 500 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | **6,500** |
| **Total** | **3,983** | **2,142** | **4,434** | **4,730** | **5,009** | **5,265** | **5,509** | **31,072** |

CEG's average unit rate for the combined replacement/refurbishment of galvanised steel and cast iron equates to $124/m (Real 2005/06) ($4,423 Divided by 35,804m). This is significantly higher than CEG's average unit rate of $95/m (Real 2005/06) achieved in the previous period and which is considered by ECG in Section 6.3.2 to be efficient in terms of meeting Section 8.16 of the Code. ECG has not been presented with any justification for the substantial forecast increase in the average unit rate.

ECG has recently become aware of probable material (pipes and fittings) price increases which will result in an increase of the replacement/refurbishment unit rate from $95/m to about $105/m. ECG therefore recommends this higher average rate for the forecast period as being efficient in terms of meeting Section 8.16 of the Code.

Based on the above, CEG's forecast mains replacement/refurbishment expenditure and that recommended by ECG is summarised in Table 7-11.

[95] AAI, December 2003 – Section 4.2.1

**Table 7-11 Comparison of CEG Forecast Expenditure and ECG Recommended Expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **CEG Forecast Mains replacement/ refurbishment** | 759 | 315 | 603 | 758 | 628 | 636 | 725 | **4,423** |
| **Recommended Mains replacement/ refurbishment** | 418 | 225 | 466 | 497 | 526 | 553 | 578 | **3,263** |

### 7.3.2 Review of Forecast Expenditure – Aged Meter Replacement

Forecast expenditure in $ 2005/06 and quantities from Section 7.3 is shown in Table 7-12. Derived unit costs are also shown.

**Table 7-12 Forecast Aged meter Replacement 2004 to 2009/10. (Real $ thousand 2005/06)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Forecast Expenditure $2005-06** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **861** |
| **Quantities** | 325 | 251 | 533 | 609 | 885 | 1,107 | 1,160 | **4,870** |
| **Average Unit Cost** | 262 | 171 | 171 | 171 | 172 | 172 | 169 | **177** |

It can be seen from Table 7-12 that the average unit cost for the forecast period is $177 (Real 2005/06). In Section 6.3.3, ECG considers that the range of $170-$180 to be an efficient cost in accordance with Section 8.16 of the Code. ECG therefore recommends an average unit aged meter replacement cost of $177 (Real 2005/06) for the forecast period.

Based on the above, ECG recommends the acceptance of CEG's forecast aged meter replacement expenditure of $861,000 (Real 2005/06).

### 7.3.3 Summary of Asset Replacement & Refurbishment

Table 7-13 summarises the ECG recommendation for forecast Asset Replacement and Refurbishment and provides a comparison with CEG forecast expenditure in real $ 2005/06.

**Table 7-13 Comparison of ECG recommendation with CEG forecast expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **ECG Recommendation** | 503 | 268 | 557 | 601 | 678 | 743 | 774 | **4,123** |
| **CEG Forecast expenditure** | 843 | 357 | 694 | 862 | 780 | 826 | 921 | **5,284** |

## 7.4 GROWTH RELATED

CEG advises[96] the forecast number of new volume customers and the related expenditure details are as shown in Table 7-14

**Table 7-14 Forecast New Customers and Unit Costs (Nominal $)**

| Financial Year | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| Residential Customer No. | - | 50 | 125 | 90 | 70 | 42 | 90 | **467** |
| Industrial & Commercial customer No. | - | 10 | 20 | 20 | 20 | 20 | 20 | **110** |
| **Total Volume Customers No.** | **-** | **60** | **145** | **110** | **90** | **62** | **110** | **577** |
| Connection Cost: ( $ / Residential Customer) | - | 1,428 | 1,458 | 1,475 | 1,523 | 1,556 | 1,568 | **--** |
| Connection Cost: ($ / I&C Customer) | - | 3,001 | 3,064 | 3,099 | 3,200 | 3,270 | 3,294 | **--** |
| Expansion Mains Cost: ($ / metre) | - | 104 | 107 | 108 | 111 | 114 | 115 | **--** |
| Reinforcement Mains Cost: ($ / metre) | - | 238 | 243 | 246 | 254 | 260 | 262 | **--** |

**Note:** No information has been provided whether the customer's numbers above are gross or net of disconnection. ECG has assumed that the numbers are gross numbers.

[96] CEG Email, Issue 1.11, 13 October 2004

CEG has also provided[97] its forecast capital expenditure for each of the above categories as shown in Table 7-15. Based on this forecast capital expenditure and the forecast customer numbers, ECG have calculated the expansion mains and reinforcement mains costs ($ per volume customer) also shown in Table 7-15. CEG has advised that its data in Table 4.5 of the AAI is in nominal $, not real $ 2003/04 as stated

ECG has derived the Total Growth Capital for 2004 as explained in section 7.2 and provided in Table 7-3.

ECG has derived the Reinforcement expenditure for 2004 and January to June 2005 by allocating 50% of the CEG estimated 2004-05 reinforcement expenditure to each of these periods.

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**Table 7-15 Forecast Growth Capital Expenditure Nominal $ thousand)**

| | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| Residential | NA | 70 | 182 | 133 | 107 | 65 | 142 | **699** |
| Industrial/ Commercial | NA | 30 | 61 | 62 | 64 | 65 | 66 | **348** |
| Less Capital Contributions | NA | -8 | -21 | -16 | -12 | -8 | -17 | **-82** |
| New Mains | NA | 207 | 423 | 427 | 441 | 451 | 454 | **2,403** |
| **Total Expansion** | **694** | **299** | **645** | **607** | **599** | **574** | **645** | **4,063*** |
| Reinforcement | 123 | 123 | 251 | 254 | 263 | 268 | 270 | **1,552*** |
| **Total Growth Capital** | **817** | **422** | **896** | **861** | **862** | **842** | **915** | **5,615*** |
| Expansion Mains Cost ($ / customer) | NA | 3,450 | 2,917 | 3,882 | 4,900 | 7,274 | 4,127 | |
| Reinforcement Mains Cost ($ / customer) | NA | 2,050 | 1,731 | 2,309 | 2,922 | 4,323 | 2,455 | |

Note: NA means Not Available

* Totals include the expenditure for 2004

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For analytical purposes, ECG has converted the forecast capital expenditure amounts to real $ 2005/06 as shown in Table 7-16.

[97] CEG Email, Issue 1.11, 13 October 2004

**Table 7-16 Forecast Growth Capital Expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| Residential Connections | NA | 71 | 182 | 130 | 102 | 61 | 130 | **676** |
| Industrial/ Commercial Connections | NA | 30 | 61 | 61 | 61 | 61 | 60 | **334** |
| Less Capital Contributions | NA | -8 | -21 | -15 | -12 | -7 | -16 | **-79** |
| New Mains | NA | 210 | 423 | 418 | 422 | 422 | 417 | **2,311** |
| **Total Expansion** | **717** | **304** | **645** | **594** | **573** | **537** | **591** | **3,962*** |
| Reinforcement | 127 | 125 | 251 | 248 | 252 | 251 | 247 | **1,501*** |
| **Total Growth Capital** | **844** | **428** | **896** | **842** | **825** | **788** | **838** | **5,462*** |
| Exp. Mains Cost ($ / customer) | NA | 3,502 | 2,917 | 3,798 | 4,689 | 6,810 | 3,780 | **-** |
| Reinf. Mains Cost ($ / customer) | NA | 2,081 | 1,731 | 2,259 | 2,796 | 4,047 | 2,249 | **-** |

Note: NA means Not Available
* Totals include the expenditure for 2004.

### 7.4.1 General Expansion / Reinforcement

ECG carried out separate analyses for the period January 2004 to June 2005 and for the period July 2005 to June 2010 (2005-06 to 2009-10). CEG advises[98] its forecasts of the numbers of new volume customers and the growth capital expenditure for these periods are as provided in Table 7-14. However, details of the forecast number of new volume customers and expenditure in each category for calendar year 2004 are not given.

ECG estimates the number of new volume customers in calendar year 2004 to be the same as forecast by CEG for financial year 2004-05 that is 99 new residential customers and 20 new industrial & commercial customers. Therefore using data from Table 7-14 it estimates there to be 179 new volume customers, consisting of 149 residential customers and 30 industrial & commercial customers.

In the absence of detailed information for 2004, ECG has analysed the expenditure for each category by assessing unit costs in the period 2004-05 to 2009-10 and applied recommended unit rate to the cost for calendar year 2004.

CEG advises[99] it has estimated 7000 metres p.a. of main laying is required for both new mains for market expansion and also new mains for reinforcement. This consists of:

[98] CEG Email, Issue 1.11, 13 October 2004
[99] CEG Email, Issue 1.11, 13 October 2004

- 2000 metres pa of mains for new customers forecast to be constructed by developers.
- 3967 metres pa of mains for new customers to be provided by CEG.
- 1033 metres p.a. of mains for a major new reinforcement project to be provided by CEG.

#### *7.4.1.1 Expansion Mains Forecast Expenditure Analysis*

The expenditure for expansion mains forecast is shown in the line item New Mains in Table 7-16. As indicated above, no information is provided on the expenditure for 2004 calendar year.

ECG has reviewed the cost for this category by considering the reasonableness of the mains length per customer and mains cost per customer.

The length of new mains constructed for the new customers is as indicated above, 3967 metres p.a.

Using the length of mains p.a. (3,967 metres), CEG advises that its forecast average length of main ranges from 36[100] to 64 metres per volume customer p.a. This is due to most subdivisions being located in outlying areas of Wagga Wagga and not close to the city as in the past. At 36 metres per customer, CEG's forecast cost of mains is $108[101] per metre

As outlined in Section 6.4.2.1, allowable unit lengths for mains to supply new customers range from less than 20 metres per new customer in New South Wales to 26 metres per new customer in new subdivisions in Canberra. ECG considers the forecast unit length of approximately 37 metres of expansion main per volume customer in Wagga Wagga is high in comparison with these other locations and in comparison with the 19.7 meters per customer achieved in Wagga Wagga during the current Access Arrangement period.

CEG advises[102] that all new residential customers in the forecast period are located in new areas or subdivisions. Therefore ECG considers that the unit length of expansion main should be more than in Wagga Wagga during the 1999 to 2003 Access Arrangement period, as longer supply mains are anticipated to be needed. However ECG also considers the unit length of expansion main should be no more than in Canberra where long supply mains are also required to supply new areas.

ECG proposes that in Wagga Wagga the efficient expenditure for new expansion mains to supply new residential customers during the next Access Arrangement period be based on its estimated efficient unit length of 25 metres of main per volume customer.

The forecast unit cost of $108 per metre is much greater than the $55 per metre unit cost that ECG recommends as efficient for the 1999 to 2003 period (refer Section 6.4.2.1),

ECG considers that for the next Access Arrangement period:

- An increase in unit cost is expected due to increased material costs for polyethylene (PE)

[100] CEG Email, Issue 1.11, 13 October 2004
[101] Market expansion expenditure divided by length of mains.
[102] CEG Email, Issue 1.21, 26 November 2004

- The average unit cost for mains extensions in the period from January 2004 to June 2010 would increase between 10% and 20% in comparison with the unit cost for new mains extensions in the 1999 to 2003 Access Arrangement period

ECG proposes the efficient expenditure for new expansion mains to supply new residential customers be based on its estimated efficient cost of $65 per metre for the next Access Arrangement period.

Therefore ECG estimates the expenditure on expansion mains for this period, based on this average cost and on its estimated unit length of 25 metres main per volume customer, is $1,625 per volume customer.

Therefore ECG estimates the expansion mains expenditure in the period January 2004 to June 2005 to be $291,000, based on its estimate in Section 7.4.1 of 179 new volume customers.  It also estimates the expansion mains expenditure for the period 2005-06 to 2009-10 to be $840,000, based on the CEG forecast in Table 7-14 of 517 new volume customers.

ECG considers these expenditures are what would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.  Therefore its recommendations are that:

1. The expenditure allowed for expansion mains in the period from January 2004 to June 2005 is its estimate of $291,000.

2. The expenditure allowed for expansion mains in the period from 2005-06 to 2009-10 is its estimate of $840,000. This has the effect of reducing the CEG expansion mains expenditure allowance for 2005-06 to 2009-10 by $1,262,000, from $2,102,000[103] to $840,000.

3. The expenditure allowed for expansion mains in the period from January 2004 to June 2010 is $1,131,000, the total of these two components.

#### *7.4.1.2 Connections Forecast Expenditure Analysis*

CEG advises[104] that its forecast unit cost ranges from $1,428 to $1,568 (Nominal) per residential connection and $3,001 to $3,294 (Nominal) per industrial & commercial connection

As advised in Section 6.4.2.2 ECG considers the efficient unit cost for a residential connection in the 1999-2003 period to be $1,150 per residential customer and $3,064 for industrial & commercial customer.  ECG anticipates the unit cost for residential connections in Wagga Wagga to increase in the next Access Arrangement period.  This is primarily due to increased material costs for Polyethylene (PE)

ECG estimates the unit cost per new residential customer connection due to these factors would increase between 5% and 10% in comparison with the unit cost for new residential customer connections in the 1999 to 2003 Access Arrangement period.  It proposes that the connection expenditure estimates for new residential customers in Wagga Wagga for the next Access Arrangement period is based on its estimated efficient average cost of $1,250 per connection.

[103] From Table 7-16, $2,313,000-$211,000 = $2,101,000
[104] CEG Email, Issue 1.11, 13 October 2004

As described in Section 7.4.1, ECG has derived from CEG data, the number of new Residential customers in the period January 2004 to June 2005 to be 149 and Industrial & Commercial customers to be 30. It calculates the connections expenditure, based on its recommended efficient unit costs of $1,250 per connection for residential customers and $3,064 per connection for Industrial & Commercial customers to be:

- $186,000 for Residential customers
- $92,000 for Industrial & Commercial customers

The CEG forecast is for 417 new Residential customers and 100 new Industrial & Commercial customers in the period 2005-06 to 2009-10. ECG estimates the connections expenditure for this period, based on its recommended efficient unit costs, to be:

- $521,000 for Residential customers
- $304,000 for Industrial & Commercial customers

ECG considers these expenditures are what would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code. Therefore ECG recommends that:

1. The expenditure allowed for connections in the period from January 2004 to June 2005 is its estimate of $278,000 (Real 2005/06).
2. The expenditure allowed for connections in the period from 2005-06 to 2009-10 is its estimate of $825,000. This has the effect of reducing the CEG connections expenditure allowance for 2005-06 to 2009-10 by $84,000, from $909,000[105] to $825,000 (Real 2005/06).
3. The expenditure allowed for connections in the period from January 2004 to June 2010 is $1,103,000, the total of these two components, including $707,000 for Residential customers and $396,000 for Industrial and Commercial customers.

### 7.4.2 Reinforcement

CEG advises[106] that a major reinforcement project consisting of 6200 metres of 200mm steel main at an estimated cost of $1,550,000 (nominal) is required to complete a ring main in Wagga Wagga. It advises this is part of the longer term strategy developed in 1998 that led to the Southern Gate Station project. It also advises that it proposes to model this shortly to confirm that this major augmentation project is still required under current conditions.

ECG calculates this cost to be $1,501,000 (Real 2005/06) and the estimated unit cost for the proposed 200mm main is about $242 per metre. CEG has not advised of any factors that would significantly alter the unit cost of 200mm steel main in comparison with the $180 per metre that ECG proposes and considers efficient for the 1999 to 2003 Access Arrangement period. (Refer Section 6.4.1).

[105] From Table 7-16, $676,000 + 334,000 - $71,000 - $30,000) = $909,000
[106] CEG Email, Issue 1.11, 13 October 2004

Therefore ECG considers the efficient unit cost for the 200mm steel ring main is $180 per metre and the efficient expenditure for the 6,200 metres of 200mm ring main is $1,116,000.

ECG has reviewed planning for this project and advises that:

- The 1998 Capacity Analysis Report[107] which provides planning information for the Southern Gate project contains no reference to this project for 6,200metres of 200mm steel main
- It has not seen any reports or analysis providing justification for this project.
- It understands CEG plans to conduct during year 2005 the network modelling needed to confirm the need for this or some other project.

ECG is unable to conclude that this project is prudent and therefore recommends that no specific allowance for expenditure on this project be included in the next Access Arrangement.

However ECG considers that consistent with accepted good industry practice, a prudent operator would provide for expenditure on currently unidentified reinforcement projects.

For the 1999-2003 period ECG recommends acceptance of an efficient expenditure of $504,000 (refer Section 6.4.1) or about $100,000p.a. for a major reinforcement project. ECG considers that to increase network capacity to supply forecast load growth and to increase network security, a similar level of expenditure on reinforcement projects is likely to be justifiable during the next Access Arrangement period.

ECG therefore recommends that an allowance for expenditure of $100,000 pa on general reinforcement projects be included in the allowable expenditure for the next Access Arrangement period. Specifically it recommends that:

1. The expenditure allowed for reinforcement projects in the period from January 2004 to June 2005 is its estimate of $150,000. This has the effect of reducing the CEG reinforcement expenditure allowance for 2005-06 to 2009-10 by $93,000, from $252,000[108] to $150,000.

2. The expenditure allowed for reinforcements in the period from 2005-06 to 2009-10 is its estimate of $500,000. This has the effect of reducing the CEG reinforcement expenditure allowance for 2005-06 to 2009-10 by $749,000, from $1,249,000[109] to $500,000.

3. The expenditure allowed for reinforcement projects in the period from January 2004 to June 2010 is $650,000, the total of these two components.

### 7.4.3 Summary

A summary of the recommended growth related expenditure to be accepted for inclusion in the capital base for the next Access Arrangement period is given in Table 7-17. The connection / mains expenditure in each year has been calculated by reducing the CEG estimates for each year in proportion to the total reduction in allowance for the period.

[107] CEG Report, Wagga Wagga Natural Gas Distribution Network Capacity Analysis, August 1998
[108] From Table 7-16, $127,000 + 125,000 = $252,000
[109] From Table 7-16, $251,000 + 248,000 + $252,000 + $251,000 + $247,000) = $1,249,000

ECG considers these are the prudent and efficient forecast expenditures for each category in the period January 2004 to June 2005 and in the period 2005-06 to 2009-10.

Consistent with section 8.16 of the Code, ECG therefore recommends that the forecast Growth Capital expenditure accepted for inclusion in the capital base for the January 2004 to June 2005 period is its estimate of $719,000 and for the 2005-06 to 2009-10 periods is its estimate of $2,165,000. ECG considers these are what would be expected of a prudent network operator acting efficiently, consistent with accepted good industry practice and in accordance with the requirements of Section 8.16 of the Code.

**Table 7-17 CEG Recommended Growth Capital Expenditure (Real $ thousand 2005/06)**

| Financial Year | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| Residential | 124 | 62 | 156 | 113 | 87 | 52 | 113 | **707** |
| Industrial/ Commercial | 61 | 31 | 61 | 61 | 61 | 61 | 60 | **396** |
| New Mains | 194 | 97 | 168 | 168 | 168 | 168 | 168 | **1,131** |
| Reinforcement | 100 | 50 | 100 | 100 | 100 | 100 | 100 | **650** |
| **Total Growth Capital** | **479** | **240** | **485** | **442** | **416** | **381** | **441** | **2,884** |

Expressed in Nominal $, the recommended growth capital expenditures for each period are as shown below in Table 7-18.

**Table 7-18 CEG Recommended Growth Capital Expenditure (Nominal $ thousand)**

| Financial Year | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Total Growth Capital** | **464** | **236** | **485** | **452** | **435** | **407** | **481** | **2,960** |

## 7.5 NON-SYSTEM CAPITAL EXPENDITURE

CEG advises in its AAI, December 2003 that Non-system assets includes direct expenditure on IT software systems and hardware, telephones, furniture and fittings and instruments, which are required to support the gas distribution business for the Wagga Gas Network.

Table 7-19 shows the forecast expenditure for non system assets as submitted in the AAI, December 2003 in Table 4.8. Note: the data for 2004 is sourced from information supplied separately by CEG[110] .

[110] CEG Email, Issue 4.1, 13 October 2004.

**Table 7-19 Forecast Non-System Capital Expenditure (Nominal $ thousand)**

| | 2004 | Jan - June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **IT Systems Software** | 245 | 123 | 251 | 256 | 262 | 268 | 274 | **1,679** |
| **Computer Hardware** | 5 | 3 | 5 | 5 | 5 | 6 | 6 | **35** |
| **Telephones** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | **7** |
| **Furniture & Fittings** | 2 | 1 | 2 | 2 | 2 | 2 | 2 | **14** |
| **Other & Instruments** | 5 | 3 | 5 | 5 | 5 | 6 | 6 | **35** |
| **TOTAL** | **258** | **131** | **264** | **269** | **275** | **283** | **289** | **1,769** |

The nominal expenditure was converted to $ 2005/06 for analysis purposes and is shown in Table 7-20.

**Table 7-20 Forecast Non-System Capital Expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan - June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **IT Systems Software** | 248 | 125 | 251 | 250 | 251 | 251 | 251 | **1,627** |
| **Computer Hardware** | 5 | 3 | 5 | 5 | 5 | 6 | 5 | **34** |
| **Telephones** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | **7** |
| **Furniture & Fittings** | 2 | 1 | 2 | 2 | 2 | 2 | 2 | **13** |
| **Other & Instruments** | 5 | 3 | 5 | 5 | 5 | 5 | 5 | **34** |
| **TOTAL** | **261** | **133** | **264** | **263** | **263** | **265** | **265** | **1,714** |

### 7.5.1 Review of Forecast Expenditure for Non System Assets.

CEG advises[111] that the forecast yearly allowances for the IT Systems Software projects reflect the total cost of each non-system capital project divided evenly over the period from 1 January 2005 until 30 June 2010. CEG advises this method of allocation is for simplicity and equity, recognising that in reality, annual expenditure will vary from year to year. Data for 2004, sourced from CEG[112] also fits within this criterion.

The separate projects that are included in the IT Systems Software comprise:

- Asset Management and Operating Support System (AMOSS) Development.
- Data capture for Asset Management System.
- Gas Network Billing.

[111] CEG Email, Issue 4.2, 24 September 2004.
[112] CEG Email, Issue 4.1, 13 October 2004.

- Middleware for Gas Network (Asset Values/Billing/AMS).

The remainder of the non-system asset capital expenditure consists of nominal allowances to cover annual replacement of information technology and communications equipment, along with fixtures, furniture and fittings.

Table 7-21 shows the breakdown of the IT Systems Software into its component projects and the allocation of expenditure across the period for each project.

**Table 7-21 Further Breakdown of IT System Software Expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan - June 2005 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | Total |
|---|---|---|---|---|---|---|---|---|
| **AMOSS System Development** | 83 | 42 | 84 | 84 | 84 | 84 | 84 | **545** |
| **Data Capture for Asset Management System** | 52 | 26 | 52 | 52 | 52 | 52 | 52 | **338** |
| **Gas Network Billing** | 56 | 28 | 57 | 57 | 57 | 57 | 57 | **368** |
| **Middleware for Gas Network (Asset Values/Billing/AMS)** | 57 | 29 | 57 | 57 | 57 | 57 | 57 | **370** |
| **Computer Hardware** | 5 | 3 | 5 | 5 | 5 | 5 | 5 | **33** |
| **Telephones** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | **7** |
| **Furniture & Fittings** | 2 | 1 | 2 | 2 | 2 | 2 | 2 | **13** |
| **Other/Instruments** | 5 | 3 | 5 | 5 | 5 | 5 | 5 | **33** |
| **TOTAL** | **260** | **133** | **263** | **262** | **263** | **263** | **263** | **1,707** |

ECG requested but has not been presented with any details of the need and justification for any of the IT System Software projects, project scopes or basis for the forecast cost estimates. No Business Cases have been made available, noting that ECG's review is being conducted during the first year of the forecast period. At the meeting in Wagga in July 2004, ECG requested details of the forecast non-system capital expenditure including FRC and generally advised CEG that for all information requests ECG required documentation on project scope, authorisation and/or business cases. ECG expected that a business case would be available for AMOSS where the project incurred costs in the current period.

The extent of ECG's knowledge regarding these costs consists of table 7-21 which was provided by CEG in response to a request for details of the "IT Systems Software" forecast expenditure shown in Table 4.8 of the AAI. CEG advises that the costs for the IT systems development and software projects listed in Table 7.21 represent the Wagga Wagga network share and the remaining items listed are nominal allowances. CEG has not provided the basis for allocating costs to Wagga Wagga but advises that the project expenditure has been allocated evenly over the forthcoming access arrangement period for reasons previously mentioned.

In summary, ECG's knowledge is limited to project titles and forecast expenditure.

The following projects are therefore analysed based on the limited information available and by making assumptions as noted.

**AMOSS System Development.**

In the period 1999 to 2003, CEG claimed expenditure for the initial phase of AMOSS. The AMOSS system, as CEG advises[113] has as its core components, a works and asset management system and the Small World graphical information system.

The CEG forecast expenditure to develop the AMOSS system over the forecast period from 2004 to 2009/10 is $545,000 (Real 2005/06) or approximately $84,000 per year. Based on its analysis in Section 7.5.1, ECG accepts that expenditure of this order may be required to complete the development and implementation of the AMOSS system. On this basis, ECG recommends the forecast expenditure but further recommends that IPART seeks more information from CEG at the next Access Arrangement Review to enable a check of the actual expenditure in accordance with the Code.

**Data Capture for Asset Management System**

ECG assumes that this project relates to capturing data from existing manual and/or electronic records and using this information to populate electronic databases associated with AMOSS. Based on ECG's industry knowledge it can be a resource intensive exercise to ensure that relevant and accurate data is recorded eg. size, material, age and maintenance history of mains, services, regulators and meters as appropriate.

Based on the assumptions made by ECG with respect to this project, the total forecast expenditure over the period from 2004 to 2009/10 is considered as what would be expected to be incurred by a prudent network operator acting efficiently in accordance with Section 8.16 of the Code.

**Gas Network Billing**

ECG assumes that the forecast expenditure relates to the Distribution Use Of System (DUOS) billing information system between CEG and gas retailers transporting gas through CEG's distribution network to supply customers. Enhancements may be required to meet evolving needs of the NSW gas market and/or retailers requirements.

Based on the aforementioned assumptions and ECG's industry experience, CEG forecast expenditure of $368,000 (Real 2005/06) over 6.5 years is recommended by ECG as being what would be expected of a prudent network operator acting efficiently in accordance with Section 8.16 of the Code.

**Middleware for Gas Network,**

ECG assumes that the forecast expenditure relates to 'middleware' software that links and provides appropriate communication interfaces between propriety application software systems which comprise AMOSS and possibly other CEG information systems. Use of middleware for this purpose is now common industry practice.

In the absence of more information from CEG, the forecast nominal annual allowance of $57,000 (Real 2005/06) appears high and it is not known if forecast AMOSS expenditure provides for middleware. Given this uncertainty ECG recommends a nominal allowance of $250,000 (Real 2005/06) for the 6.5 year forecast period

[113] [113] CEG Email, Issue 4.1, 13 October 2004.

**Computer Hardware, Telephones, Furniture & Fittings, etc.**

Forecast expenditure appears to be based on nominal allowances for the items. Given the size of the CEG network and business, ECG considers the total forecast allowance of $86,000 (Real 2005/06) to be reasonable and in accordance with the actions of a prudent network operator acting efficiently under Section 8.16 of the Code.

### 7.5.2 Summary of Non System Forecast Recommendations.

ECG has reviewed the data available for forecast expenditure for non system assets and using this information and ECG's experience recommends expenditure of $1,597,000 (Real 2005/06) as the amount that would be invested by a prudent network operator acting under Section 8.16 of the Code.

**Table 7-22 Comparison of ECG recommendation with CEG Forecast expenditure (Real $ thousand 2005/06)**

| | 2004 | Jan-June 05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **ECG Recommendation** | 248 | 123 | 245 | 245 | 245 | 245 | 245 | **1,597** |
| **CEG Forecast expenditure** | 261 | 133 | 264 | 263 | 263 | 265 | 265 | **1,714** |

## 7.6 REDUNDANT CAPITAL & ASSET DISPOSALS

CEG advises[114] that it expects no significant redundant capital or asset material disposals during the forecast period from 2004 to 2009-2010. ECG based on its experience, accepts this advice given most of the network assets are long life and Wagga Wagga is a relatively small network where system changes do not generally warrant disposal of assets before the end of their economic lives.

Mains and services that are rehabilitated will be either retained on the books as conduits for new inserted assets or will be fully depreciated.

Meters are predominantly replaced at the end of their economic lives and will have no book value. Meters are occasionally replaced for other reasons eg. larger meter required, but these are generally retested and reused.

[114] AAI December 2003, section 4.2.2

## 7.7 CAPITAL CONTRIBUTION

Sections 8.23 and 8.24 of the National Gas Access Code allow for capital contributions by customers and the regulatory capital base excludes these capital contributions from the expenditure required in providing gas supply.

CEG have forecast the capital contributions in the current Access Arrangement period[115] to be as in Table 7-23.

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**Table 7-23 Forecast Capital Contributions 2004 to 2010**
**Total (Nominal $ thousand)**

| | 2004 | Jan-June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **Capital Contribution** | 48 | 8 | 21 | 16 | 12 | 8 | 16 | **129** |

These contributions are about 2% of forecast growth capital and ECG considers based on its experience that this is efficient. Therefore ECG considers the capital contributions to meet the Code's requirements.

ECG therefore recommends the capital contribution totalling $129,000 (Nominal) is accepted for inclusion in the calculation of the Regulatory Capital Base.

## 7.8 RECOMMENDATION FOR CAPITAL EXPENDITURE 2004 TO 2010

It is proposed that the capital expenditure from 2004 to 2010 shown in Table 7-24 is allowed for inclusion in the initial capital base for the next Access Arrangement period.

**Table 7-24 Recommended Capital Expenditure 2004 to 2010**
**(Real $ thousand 2005/06)**

| | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **Asset Replacement** | 418 | 225 | 466 | 497 | 526 | 553 | 578 | **3,263** |
| **Meter Replacement** | 85 | 43 | 91 | 104 | 152 | 190 | 196 | **860** |
| **Growth Related** | 479 | 240 | 485 | 442 | 416 | 381 | 441 | **2,884** |
| **Non-system assets** | 248 | 123 | 245 | 245 | 245 | 245 | 245 | **1,596** |
| **Total** | **1,230** | **631** | **1,287** | **1,288** | **1,339** | **1,369** | **1,460** | **8,603** |

[115] AAI, Table 4.7, December 2003

# 8. NON CAPITAL COSTS 1999 TO 2003

## 8.1 INTRODUCTION

Operating, maintenance and other non capital costs are also significant components of the revenue requirement for CEG. Sections 8.36 and 8.37 of the Gas Code cover the provisions related to recovery of non capital costs.

- Section 8.36 defines non capital costs as the operating, maintenance and other costs incurred in the delivery of a reference service.
- Section 8.37 states that reference tariffs may provide for the recovery of all non-capital costs except for any costs that would not be incurred by a prudent service provider, acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering the reference services.

The Code does not specifically outline the approach that has to be adopted to determine the efficient cost for a level of service. A possible approach would involve benchmarking CEG's cost performance against that for other Australian gas distributors. For a benchmarking approach to provide the level of information required by this review, it would have been necessary to obtain detailed costing information from CEG and other service providers. This information is not available and therefore this approach is not achievable.

An alternative approach would be to carry out a detailed scrutiny of the various activities associated with CEG's operations to assess the prudence of operating expenditure. This would have necessitated a much more intrusive process than was possible for this review. In addition, such an approach would require CEG to have sufficient documentation of its processes. ECG does not believe that CEG is able to provide this documentation for such an analysis to be carried out.

Consequently ECG assessed the non capital costs in the following manner:

- The Tribunal's decision in the 1999 Access Arrangement was used as the starting basis for the non capital expenditure.
- Actual costs during the 1999-2004 Access Arrangement period were reviewed to assess trends, anomalies and differences in the various categories.
- Categories of non capital expenditure were analysed to determine the reasonableness of the costs for the service provided.
- Where possible, costs in particular categories were compared (e.g. total operating costs) with those of other gas distribution companies in Australia.
- CEG's own forecasts of costs were reviewed, together with the methods, processes and data used to derive them.
- Conclusions were then drawn about the efficient cost for the current Access Arrangement period after taking into account the various components of non capital expenditure. This cost will be the starting point for establishing the non capital expenditure for the period from January 2004 to June 2010.

Details of the review are provided in the sections below.

## 8.2 CEG OPERATIONAL ARRANGEMENT

CEG entered into a Memorandum of Understanding (MOU) with CE Service Delivery Division (CE Service Delivery) which commenced on 31 October 2003. CEG advises[116] that this arrangement was put in place after competitive tenders were received from CEG Service Delivery and Agility as a potential service provider.

CEG did not provide evidence that the competitive tender process was run. However, this issue was discussed in detailed at the meeting with CEG in July. CEG advised then that this process took place 2-3 years ago and reconfirmed[117] the tender process took place was carried out.

A copy of the MOU was provided to ECG for the purposes of this review.

The MOU is for a 2 year term to 2005 with provision for the schedule of services to be reviewed annually. In broad terms, it requires CE Service Delivery to:

- Operate and maintain the gas network as the agent of CEG.
- Ensure compliance with all of CEG's policies, directions and resolutions relevant to the operation of gas networks.
- Provide the services:
    - In a competent, timely and cost effective manner
    - In accordance with any budget or business plan and policies adopted or approved by CE Gas Board
    - In accordance with all applicable laws, licensing, regulatory and administrative requirements and Australian Standards relevant to the operation of the CEG distribution system.
- Report at specified intervals on its performance.
- Comply with its agreed service standards.

Payment of services is set out in section 6 of the MOU. The CE Service Delivery renders an invoice to CEG at the start of each month. Following CEG verification of the details of the payment and processing of the invoice, the Finance Division carries out a journal transfer at the end of the month.

Most of CEG's operating and maintenance functions are carried out by CE Service Delivery under the MOU. These functions include emergency call centre operations, preventative maintenance on mains, services and meters and reactive maintenance on mains, services and meters.

CEG also contracts out other specialised functions to unrelated third parties Furmanite Pipeline Support, Abigroup and Gas Technology Services as set out below. Tenders are conducted for contracts which exceed $100,000. Contracts run for a 12 month period after which alternative suppliers are sought[118]. Services costing between $20,000 and $100,000 are handled by requesting quotes from two or three providers although often only one provider is able to deliver the requested service within the relevant network area.

[116] ECG meeting with CEG in Wagga Wagga in July 2004
[117] Reconfirmed by CEG Phil Coulton in December 2004.
[118] CEG email Issue 5.9, 22 October 2004

**Furmanite Pipeline Support**

A retainer is paid by CEG to Furmanite to provide specialist repairs to steel pipes on call.

**Abigroup**

Abigroup provides leak survey services and cathodic protection potential surveys. Leak surveys of high risk areas such as shopping centres and schools are conducted annually. The remainder of the network is divided into quarters with one quarter is surveyed each year at the same time as the high risk areas.

Cathodic protection potential surveys of the steel pipe within the network are conducted twice a year.

**Gas Technology Services**

Gas Technology Services provides:

- Gas quality audits at receipt points and fringe areas of the network at a frequency of four times per year.
- Annual calibration of volume correcting devices.

## 8.3 CEG 1999 TO 2004 NON CAPITAL COSTS

At the time of issue of the Final Decision in 1999 Great Southern Energy had only been operating the gas network for 18 months following the purchase of the asset from the Council of the City of Greater Wagga Wagga. The Final Decision 1999 noted that Great Southern Energy was likely to harness economies of scale from operating an integrated energy business but because of the limited operating history, the extent of this effect would be examined at the next review. The merging of the gas and electricity businesses offered potential cost savings in areas such as meter reading, plant and equipment and technical design and supervision. The Final Decision required a real cost reduction of 1% per annum.

Table 8-2below sets out the Non Capital Costs in the Access Arrangement Information drafted and approved by the Tribunal in September 1999. Table 8-3 presents the same data in real $ 2005/06.

The CPI adjustment factors used to convert the Non Capital Costs to 2005/06 are shown in the Table 8-1

**Table 8-1 CPI and Conversion Factors for Non Capital Expenditure**

| Calender Years | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|
| CPI | 1.47 | 2.92 | 2.87 | 3.00 | 2.77 |
| Conversion factors | 1.1839 | 1.1503 | 1.1182 | 1.0856 | 1.0564 |

**Table 8-2 Non Capital Costs in 1999 Access Arrangement Information (Real $ thousand 1999)[119]**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Operating & Maintenance Costs** | 1,269 | 1,256 | 1,243 | 1,233 | 1,221 | **6,222** |
| **Corporate Overheads** | 225 | 223 | 221 | 218 | 216 | **1,103** |
| **Marketing Costs** | 140 | 139 | 137 | 136 | 134 | **686** |
| **Total Non Capital Costs** | **1,634** | **1,618** | **1,601** | **1,587** | **1,571** | **8,011** |

**Table 8-3 Non Capital Costs in 1999 Access Arrangement Information (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Operating & Maintenance Costs** | 1,502 | 1,487 | 1,472 | 1,460 | 1,446 | **7,367** |
| **Corporate Overheads** | 266 | 264 | 262 | 258 | 256 | **1,306** |
| **Marketing Costs** | 166 | 165 | 162 | 161 | 159 | **813** |
| **Total Non Capital Costs** | **1,934** | **1,916** | **1,895** | **1,879** | **1,860** | **9,486** |

To assist in establishing the efficient level of non capital expenditure for the period 1999 – 2003 as a base ECG sought additional information from CEG on its actual non capital expenditure for the period.

In response to this request, CEG has provided the expenditure shown in Table 8-4[120]. The table provides a breakdown by calendar year of CEG's non capital costs. For the purpose of this analysis, ECG has converted the expenditure to real $ 2005/06 as shown in Table 8-5.

**Table 8-4 Breakdown of Actual Non Capital Costs 1999 to 2004 (Nominal $ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Service Delivery O&M** | 865 | 662 | 779 | 999 | 885 | 4,190 |
| **Gas Network Management** | 508 | 598 | 453 | 308 | 378 | 2,246 |
| **Subtotal O&M** | **1,373** | **1,260** | **1,232** | **1,307** | **1,263** | **6,436** |
| **Marketing** | 142 | 71 | 122 | 53 | 97 | 485 |

[119] 1999 AAI, p31

[120] CEG email Issue 5.24, 8 November 2004.

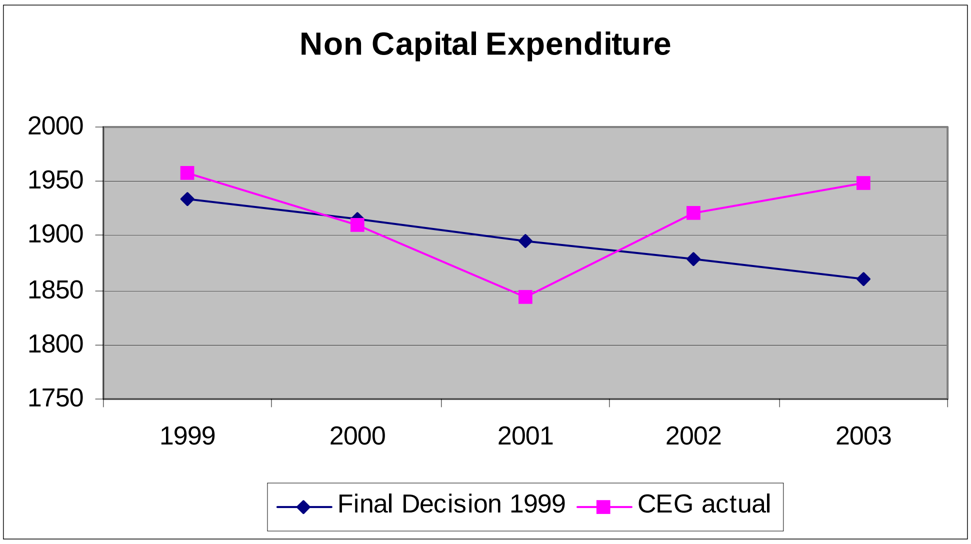
| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Corporate Allocation** | 138 | 330 | 294 | 409 | 484 | 1,655 |
| **Full Retail Contestability** | | | 142 | 142 | 142 | 426 |
| **Total** | **1,654** | **1,661** | **1,790** | **1,911** | **1,986** | **9,002** |

**Table 8-5 Breakdown of Actual Non Capital Costs 1999 to 2004 (Real 2005/06$ thousand)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Service Delivery O&M** | 1,025 | 761 | 871 | 1,085 | 935 | **4,677** |
| **Gas Network Management** | 601 | 688 | 507 | 334 | 400 | **2,530** |
| **Subtotal O&M** | **1,626** | **1,449** | **1,377** | **1,419** | **1,334** | **7,207** |
| **Marketing** | 168 | 82 | 136 | 58 | 102 | **546** |
| **Corporate Allocation** | 164 | 379 | 329 | 444 | 511 | **1,827** |
| **Full Retail Contestability** | | | 159 | 154 | 150 | **4,63** |
| **Total** | **1,958** | **1,911** | **2,001** | **2,075** | **2,098** | **10,043** |

CEG's actual non capital costs for the period 1999-2003 were $ 10,042,000, compared with allowable costs of $ 9,484,000 (Real 2005/06) i.e. a variance of $ 558,000 ( 6% increase). It can be seen in Figure 8-1 that the underspending in 2000 and 2001 (relative to levels allowable in the Final Decision 1999) was offset by higher spending in the later years

**Figure 8-1 CEG Non Capital Expenditure**




Note: The actual non capital expenditure does not include FRC costs.

The review on each category for the Non Capital expenditure is detailed in the sections below.

### 8.3.1 Operation and Maintenance Expenditure

CEG advises that its operating and maintenance (O&M) expenditure can be divided into two activities[121]; service delivery and gas network management.

Service Delivery is the direct O&M costs for operating the networks. It includes such activities as city gate maintenance, regulator maintenance, leak repairs, inventory and supplies, network engineering, environmental management, technical assurance, subscriptions to standards and code preparation bodies, cost of gas control and network planning.

Gas Network Management is the O&M costs for managing the gas networks. It includes such activities as asset management functions, network data and billing and strategic planning and compliance activities.

Details of the O&M expenditure for the period 1999 to 2003 is provided in Table 8-6.

**Table 8-6 Final Decision versus O&M Expenditure (Real $ thousand 2005/06)**

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Approved O&M** | 1,502 | 1,487 | 1,472 | 1,460 | 1,446 | **7,367** |
| **Service Delivery O&M** | 1,024 | 761 | 870 | 1,085 | 934 | **4,677** |
| **Gas Network Management** | 601 | 688 | 506 | 334 | 399 | **2,531** |
| **Total O&M** | **1,626** | **1,449** | **1,377** | **1,419** | **1,334** | **7,208** |

The above table shows that over the five-year period, the total O&M cost ($7,208,000) is less than the Final Decision 1999 amount ($7,367,000). In addition, over this period 1999 to 2003, the number of customers significantly increased above forecast, However, the industrial load was lower than forecast principally due to the loss of one major customer, Laminex Industries. The additional customer numbers would have a greater impact on costs versus the reduction in the industrial load. As such, given the actual O&M cost is 98% of the amount in the Final Decision 1999, ECG believes that CEG's expenditure for this period is at the efficient level. However, the question remains whether the 2003 level is representative of the efficient level and can be used as the starting point for reviewing the forecast O&M cost.

ECG has therefore considered the factors that have contributed to CEG's expenditure for this period in the categories shown in the table above and whether the 2003 expenditures are representative of efficient levels.

**Service Delivery**

The expenditure in the service delivery has fluctuated over this period. This would have contributed to the reduction in the total O&M. The main reason for the changing levels of expenditure is that CEG deferred some preventative maintenance activities in 2000 and 2001 but then increased the workload in 2002 to address the issues. No information has been provided to whether CEG has overcome the entire backlog. However given that the expenditure is approximately mid way higher between the 2001 and the 2002 levels, ECG believes that it is likely that CEG would have addressed the backlog and has returned to a work volume equivalent to the level that is required for CEG to comply with the various Codes and Standards.

[121] 2003 AAI pg 39

To assist in deciding on whether the 2003 expenditure is at the efficient level, ECG sought information from CEG on the labour rates that it had negotiated with the Service Delivery or other contractors. In response, CEG provided the unit rate but considered this information confidential. Table 8-7 details the unit rates provided by CEG[122].

**Table 8-7 Unit Labour Costs**

[This table is confidential.]

ECG has assumed that the operation is either on a per hourly basis or on a per job basis. Based on its industry experience, ECG considers the rates to be reasonable

Based on the above analysis, ECG therefore considers that the $934,000 in 2003 is at the efficient level to be used as the starting point for reviewing the forecast expenditure for the period January 2004 to June 2010.

**Gas Network Management**

CEG advises that a staff engineer resigned from CEG in 2002. CEG has yet to replace this position. CEG has indicated that the loss of the engineer has had an impact on its operations. Gas modeling activities have been reduced following this departure. CEG also advised that there are only 5 staff in this group. ECG considers that given the range of activities that the group has to cover, this staffing level is not sustainable in the long term. ECG believes that the engineer will need to be replaced in the short to medium term.

**Summary**

ECG therefore accepts the CEG level of expenditure for 2003 as the efficient level but considers that in the short to medium term, CEG may need to review its decision not to replace the engineer.

### 8.3.2 Corporate Allocation

CEG advises that the category Corporate Allocation is the corporate costs which have been assigned to CEG. The corporate costs include billing, accounts payable, credit control, call centres, emergency response, finance and accounting, payroll, business development, property management, customer relations and human resources.

In its 2003 AAI, CEG states that these costs have been allocated on the following basis:

- Total corporate costs have been allocated to gas on the basis of an independently prepared cost allocation methodology that was developed for use in the 2002/03 regulatory accounts.
- Gas corporate costs have been allocated between the gas network and gas retail functions on the basis of the relative share of revenue realised by each function.

[122] CEG email Issue 5.23, dated 8 November 2004

- Gas network corporate costs have been allocated to the Wagga Wagga Networks on the basis of the Wagga Wagga Network's relative share of direct expenditure as a proportion of total gas network expenditure in 2003/04[123].

CEG's expenditure compared to the Tribunal's Final Decision 1999 is shown in Table 8-8.

**Table 8-8 Actual versus Approved Corporate Allocation (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Approved** | 266 | 264 | 262 | 258 | 256 | 1306 |
| **Actual** | 163 | 379 | 328 | 443 | 511 | 1824 |

As can be seen in the above table, CEG's Corporate Allocation has increased significantly since 1999. In addition, the expenditure in 2003 is double the level at which the Tribunal considered efficient in its Final Decision 1999. Before coming to its decision on whether the 2003 is at an efficient level for 2003, ECG reviewed the factors that have contributed to this increase in cost.

One of the factors that that has resulted in the cost increase is the introduction of GST. CEG advises that there are currently two members of staff responsible for fulfilling GST obligations and estimates that the GST task imposes work requirements approximately equivalent to 35% of a full-time position.

CEG also advises that a number of dedicated project teams were established in the three predecessor organisations of Country Energy to coordinate and manage the various aspects of GST implementation. These included information systems, billing, accounts payable, accounts receivable, finance, retail, networks, regulatory affairs, energy trading and corporate communications.

Another factor that has also resulted in a cost increase is the escalation of the insurance costs. Insurance costs have increased markedly in recent years with factors such as the HIH collapse and the 11 September 2001 terrorist attacks having a major impact. CEG has provided details of insurance premiums paid by Country Energy in recent years for Workers Compensation, Public Liability and Industrial Special Risk. CEG pays an allocated portion of these premiums.

CEG advises that for Country Energy as a whole, the total premiums for the above categories of insurance were 33% higher in 2003/04 than the previous year ($13 million compared to $9.7 million)[124]. In 2002/03 the Public Liability premium rose by 49% over the previous year. In 2003/04 the Workers Compensation premium increased by 68% over that of the previous year. Whilst CEG has not provided any information regarding the proportion of the insurance costs borne by CEG's Wagga Wagga network, ECG acknowledges that there have been significant changes to the insurance costs and that it would contribute to the increase in the Corporate Allocation.

Another factor worth considering is the increase in Corporate Allocation as a percentage of the total Non Capital cost and also as a percentage of the O&M. This is detailed in Table 8-9 which shows that the Corporate Allocation has increased from 8% of the total Non Capital Cost to 24% in 2003.

[123] Country Energy Gas' other networks include the systems serving towns including Cooma, Tumut, Bombala, Culcairn, Holbrook and Temora.
[124] CEG email Issue 5.3, dated 22 October 2004.

**Table 8-9 Percentage breakdown of Non Capital Costs 1999 to 2004**[125]

| | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|
| Corporate Allocation | 8% | 20% | 16% | 21% | 24% |
| O&M | 83% | 76% | 69% | 68% | 64% |
| FRC | 0% | 0% | 8% | 7% | 7% |
| Marketing | 9% | 4% | 7% | 3% | 5% |

This also means that the Corporate Allocation costs as a percentage of the O&M costs have increased from 10% in 1999 to 37%[126] in 2003. In the total cost review on AGL in NSW, ECG identified that the Corporate Allocation category as a percentage of the O&M is in the order of 30%. Based on the total cost study and its experience, ECG believes that this allocation is therefore high.

Whilst it is acknowledged that the factors such as insurance and other related costs would have contributed to the increases, another factor that could result in the cost increase especially in 2003 is CEG's cost allocation. CEG engaged PriceWaterhouse Coopers (PWC) to develop an allocation methodology in 2003. Whilst CEG has not provided any information on when it first applied this methodology, ECG believes that it is likely that the methodology was applied in 2003 which would partially explain the cost increase in that year.

In support of the allocation methodology, CEG provided a copy of PWC's report to ECG[127]. ECG recognises that a review on the allocation methodology is outside the scope of this project. However, in considering the reasonableness of the cost, ECG has considered the PWC report. As the work was carried out by an independent consultant, PWC, ECG accepts the allocation methodology.

Given that ECG has acknowledged that there are grounds for cost increases, ECG believes that it is likely that the cost of the Corporate Allocation for 2003 would be considered reasonable.

### 8.3.3 Marketing

One of the issues identified by stakeholders in Victoria, NSW and Canberra as part of the Access Arrangement reviews is the quantum of the marketing budget. As shown in Table 8-9, CEG's actual marketing expenditure as a percentage of the Non capital expenditure has decreased from 9% in 1999 to 5% in 2003. In real terms, CEG's marketing expenditure has decreased from $163,000 in 1999 to $102,000 in 2003. This is less than the Final Decision 1999 approved level of $159,000 in 2003. The question still remains whether this should be the efficient level as the starting point for the period January 2004 to June 2010.

CEG advises that the marketing expenditure is for promotional programs including spending to ensure that new properties are connected to the network and the promotion of

[125] Derived from CEG email Issue 5.24, dated 12 November 2004.
[126] Corporate Allocation divided by O&M.
[127] The Development of a Detailed Cost Allocation Methodology, PriceWaterhouse Coopers, November 2003.

gas and gas appliances to existing customers. CEG has also indicated that all customers benefit from the higher utilisation of the network arising from the payment of incentive to new customers.

A key focus of the policy is to achieve a high percentage of connections to new homes where the appliance installation costs are generally lower than for an existing home. If a new home is connected, the additional gas load is generally available for the life of the appliances and beyond because in most cases new gas appliances replace old gas appliances.

A further benefit to CEG of connecting a new home is that the costs of reinstatement tend to be considerably lower for new homes because installation of mains and services can occur before gardens, driveways etc. are established.

ECG is aware that gas appliances have a higher installed cost than their electric equivalents so that the householder typically faces expenses of several hundred extra dollars if gas is to be installed (typically in the range $200-$800). Moreover, the new home market is extremely price sensitive. By contrast, climatic conditions and more attractive price relativities in centres such as Melbourne and Adelaide have traditionally made gas the fuel of choice for space heating and water heating. The result is that the consumer gas culture which exists in Victoria and South Australia is much weaker in NSW. In inland areas of NSW where the space heating load is greater, gas tends to be more favourably perceived by consumers than in coastal areas but the barrier imposed by the higher installed cost of gas appliance remains.

ECG considers that incentive payments also play an important role where natural gas is connected to new areas by inducing a higher initial level of utilisation of the gas network. This important influence has been recognised in policy considerations relating to new networks proposed in Victoria where expansion had been significantly reduced in the new gas market environment.

Following discussions with CEG about its marketing strategy and policies, ECG concluded that the provision of incentive payments is an appropriate mechanism for assisting the growth of the gas market in Wagga Wagga. Initiatives aimed at cost effectively increasing network utilisation are in accordance with the Code requirements (section 8.37) for a service provider to act efficiently and minimise the average cost of gas to all consumers.

While CEG's marketing expenditure was below the levels allowed in the Final Decision 1999, the lowest levels occurred in a period when demand for new appliances was driven by a higher level of housing construction as shown in Table 8-10. Hence, even though the allowable expenditure was not spent, demand significantly exceeded forecast levels.

**Table 8-10 Volume Customer Numbers**

| | **Forecast No. Volume Customers**[128] | **Actual No. Volume Customers**[129] | **Annual increase in customer no.** | **Increase over previous year** |
|---|---|---|---|---|
| **1998** | NA | 14,327 | | NA |
| **1999** | 14,470 | 14,674 | 347 | 2.4% |
| **2000** | 14,615 | 15,370 | 696 | 4.7% |
| **2001** | 14,761 | 16,127 | 757 | 4.9% |
| **2002** | 14,909 | 16,651 | 524 | 3.2% |
| **2003** | 15,058 | 16,798 | 147 | 0.9% |

[128] Access Arrangement Table 2.3, p15
[129] Access Arrangement Table 2.3, p15 and email from CEG dated 10 September 2004

From Table 8-10, the total increase in customer numbers from 1999 to 2003 is 2,471. This increase in customer number has not included the customers that have been disconnected from the system. The number of disconnections has not been provided.

The average level of marketing expenditure per new customer in the period 1999-2003 was $221 (2005/06)[130] which is considered to be efficient in accordance with the Code.

ECG concludes that CEG's marketing expenditure in 2003 was that of a prudent operator, acting efficiently in accordance with the Gas Code.

### 8.3.4 Full Retail Contestability

In the 1999 Final Decision there was no mechanism provided for the recovery of costs associated with the introduction of Full Retail Contestability (FRC).

FRC costs incurred by Country Energy were reviewed for the Tribunal by PB Associates who provided a Final Report and a Supplementary Report. Both of these reports were provided to ECG by CEG as part of its review. PB Associates recommended that the non capital costs of $535,786[131] be accepted as prudent and efficient.

The allocation of FRC costs between the various gas networks owned by CEG was determined on the basis of customer numbers. The Wagga Wagga network was allocated 76.15% of these costs since 16,783 of CEG's 22, 039 customers at the time were served by the Wagga Wagga network.

The Tribunal agreed these FRC costs were reasonable costs associated with the introduction of contestability in a letter dated 10 July 2002. As no further information was provided, ECG has used the work done by PB Associates to assist in deciding to accept that the costs are efficient in accordance with the Gas Code.

## 8.4 ECG'S VIEW ON EFFICIENT 2000 TO 2003 NON CAPITAL COSTS

As discussed in Section 8.1, ECG proposes to use the efficient cost for the current period as shown in Table 8-11 as the starting point for reviewing the Non Capital Costs for the next AA period.

**Table 8-11: ECG's view of efficient Non Capital Costs 1999 to 2003 (Real $ thousand 2005/06)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | Total |
|---|---|---|---|---|---|---|
| **Service delivery O&M** | 1025 | 761 | 871 | 1085 | 934 | **4,676** |
| **Gas Network Management** | 601 | 688 | 507 | 334 | 400 | **2,530** |
| **Sub total O&M** | 1,626 | 1,449 | 1,377 | 1,419 | 1,334 | **7,205** |
| **Corporate Overheads** | 163 | 379 | 329 | 444 | 511 | **1,826** |
| **Marketing Costs** | 168 | 82 | 136 | 58 | 102 | **546** |

[130] Total expenditure of $546,000 divided by 2471 customers from Table 8-10.
[131] And $870,134 in capital expenditure as set out in 6.5.2 of this report

| | | | | | | |
|---|---|---|---|---|---|---|
| **FRC** | 0 | 0 | 159 | 154 | 150 | **463** |
| **Total Non Capital Costs** | **1,957** | **1,910** | **2,002** | **2,075** | **2,097** | **10,041** |

**Note:** ECG considers that UAG and Government Levies will contribute to the non capital expenditure. However, as these costs have not been separately identified in the AAI December 2003, ECG is unable to indicate whether the costs have been included in the above categories.

As such, ECG has provided a separate discussion on both items in Appendix 2.

# 9. NON CAPITAL COSTS 2004 TO 2010

## 9.1 CEG FORECAST EXPENDITURE

In its AAI 2003, CEG advises that for the period July 2005 to June 2010, it has forecast an annual non capital cost of $2,170,000 (Real 2003/04). CEG has also indicated that as the non capital expenditure increases with increased customer numbers, the non capital cost represents a real reduction on a per customer basis for the forecast period.

CEG has also indicated that a substantial proportion of operating costs was tendered out to the market in 2003 and contractual arrangements which commenced on 1 July 2003 now apply until 30 June 2005.

These forecast costs are set out in Table 9-1. As discussed in section 2, the next Access Arrangement period is unlikely to commence before 1 July 2005. Accordingly for the purpose of the cost review, ECG has included the period from January 2004 to June 2005 in this section of the review.

The AAI 2003 did not include the cost for the calendar year 2004. In response to a request from ECG, CEG has provided the information in a separate email[132]. Table 9-1 has therefore included the costs for the calendar year 2004.

For the purpose of the analysis, the forecast expenditure has been converted to real $ 2005/06 as shown in Table 9-2.

**Table 9-1 Non Capital Cost Forecast (Real $ 2003/04)[133]**

| | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Network Operating and Maintenance** | 937 | 477 | 953 | 953 | 953 | 953 | 953 | **6,179** |
| **Marketing** | 142 | 70 | 140 | 140 | 140 | 140 | 140 | **912** |
| **Direct Network Gas Management** | 433 | 214 | 428 | 428 | 428 | 428 | 428 | **2,787** |
| **Corporate Allocation** | 586 | 290 | 580 | 580 | 580 | 580 | 580 | **3,776** |
| **FRC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Regulatory Costs** | 0 | 25 | 50 | 50 | 50 | 50 | 50 | **275** |
| **Service Standards Administration** | 0 | 10 | 20 | 20 | 20 | 20 | 20 | **110** |
| **Total** | **2,098** | **1,085** | **2,171** | **2,171** | **2,171** | **2,171** | **2,171** | **14,038** |

[132] CEG email Issue 5.24., dated 8 November 2004
[133] CEG AAI, Table 5.1 p38

**Table 9-2 Non Capital Cost Forecast (Real $ 2005/06)**

| | 2004 | Jan to June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Total |
|---|---|---|---|---|---|---|---|---|
| **Network Operating and Maintenance** | 969 | 499 | 997 | 997 | 997 | 997 | 997 | **6,453** |
| **Marketing** | 146 | 73 | 146 | 146 | 146 | 146 | 146 | **949** |
| **Direct Network Gas Management** | 447 | 224 | 448 | 448 | 448 | 448 | 448 | **2,910** |
| **Corporate Allocation** | 606 | 303 | 607 | 607 | 607 | 607 | 607 | **3,943** |
| **FRC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Regulatory Costs** | 0 | 26 | 52 | 52 | 52 | 52 | 52 | **286** |
| **Service Standards Administration** | 0 | 10 | 21 | 21 | 21 | 21 | 21 | **115** |
| **Total** | **2,168** | **1,136** | **2,271** | **2,271** | **2,271** | **2,271** | **2,271** | **14,656** |

Details of the review on the forecast expenditure for the period January 2004 to July 2010 are provided in the sections below.

### 9.1.1 Operating and Maintenance Expenditure

As discussed in section 8.3.1, Operating and Maintenance (O&M) expenditure consists of the following two categories shown in the table above:

- Network Operating and Maintenance which is also referred to as Service Delivery O&M in the period 1999 to 2003. The costs are for the direct operating and maintenance costs pertaining to the network. This category includes such items as city gate maintenance, regulator maintenance, leak repairs, inventory and supplies, network engineering, environmental management, technical assurance, subscriptions to standards and code preparation bodies, cost of gas control and network planning.

- Direct Network Gas Management is also referred to as Gas Network Management in the period 1999 to 2003. The costs are for the directly attributable costs of managing the gas network. The relevant functions include asset management functions, network data and billing and strategic planning and compliance activities.

As discussed in section 8.1, ECG has used as the starting point the efficient cost in 2003 to assess the efficiency of the cost in the forecast period. In section 8.4, ECG recommended that the efficient cost for 2003 O&M expenditure is $1,334,000. This cost consists of $934,000 for Network Operating and Maintenance and $400,000 for Direct Network Gas Management.

Without changing circumstances, O&M expenditure should not change significantly from year to year. However, as shown In Table 9-2, the cost for 2004 calendar year for Network Operating and Maintenance is $969,000 and for the each of the following financial years is $997,000. Similarly the costs for the 2004 calendar year for Direct Network Gas Management are $447,000 and for each of the following financial years is $448,000.

CEG has provided some information supporting the cost increase. However, the data provided has only enabled ECG to carry out a qualitative review.

**Network Operating and Maintenance**

In response to a request from ECG, CEG has provided a breakdown of its forecast Network Operating and Maintenance costs which is set out in Table 9-3 below.

**Table 9-3 Gas Network Operating and Maintenance Costs[134]**
**($thousand)**

| | 2003/04-09/10 Annual Forecast[1] Real $ 03/04 | 2002/03 Actual Nominal $ | 2003/04 Actual Nominal $ |
|---|---|---|---|
| **Customer services** | 165 | 157 | 179 |
| **Gas Operations** | 175 | 155 | 176 |
| **Preventative Maintenance** | 195 | 131 | 148 |
| **Reactive Maintenance** | 418 | 424 | 408 |
| **Total Network O&M Costs** | **953** | **867** | **911** |

Note 1:2003-04 expenditure is from 2003 AAI in real $ 2003/04 as provided by CEG,

As shown in Table 9-3, CEG has forecasted an annual expenditure of $953,000 for its Network Operating and Maintenance activities for the period 2003/04 to 2009/10. However, as shown in Table 9-3, the actual costs for 2003/04 have increased from 2002/03. As there is only limited information on the details behind the cost increase, ECG has carried out a qualitative review of the costs.

From the information provided, ECG believes that the factors that would contribute to the cost increases include wage rises, increased customer numbers and additional security to network assets.

**Wage Rise**

CEG advises that from July 1999 there has been a number of wage rises. CEG has provided Table 9-4 detailing the wage increase from 1999 to 2004.

[134] CEG email Issue 5.24, dated 8 November 2004.

**Table 9-4 CEG Award Wage Increases**

[This table is considered confidential.]

From the table above, there has been a 32% pay increase from 1999 to 2004. ECG therefore believes that this wage rise would have an impact on the cost increase from 2003 to 2004.

**Security of Network Assets**

CEG advises that there have been increased obligations in security, risk and emergency management and also consumer privacy and protection legislation.

CEG also has advised that there have been increased costs relating to security measures since the events of 11 September 2001[135]. In 2002/03 Country Energy formed a dedicated security branch to manage and coordinate the implementation of increased security measures and initiatives. This occurred in response to growing obligations and concerns about potential threats to Country Energy infrastructure. The total capital and operating costs of this branch are reported by CEG to have been $5.85 million in 2002/03 and 2003/04[136]. Forecast costs for the next three years are $21.6 million[137].

The following specific security measures have been introduced by CEG[138]:

- Security identification cards for all employees, visitors and consultants.
- Electronic single entry point access to all regional offices, customer service centres, most field service centres and all zone substations.
- Closed circuit TV and other security devices to provide rapid detection and response to critical infrastructure and high volume customer service sites.
- Security monitoring patrols to identify critical infrastructure sites and other sites identified as potentially vulnerable to security breach.
- IT security capability.
- Increased network security around zone substations.
- Development of increased employee awareness of security.
- Development of policy and procedures relating to critical infrastructure.
- Document sensitivity management, security manuals, crisis management and recovery.
- Business impact analysis to aid business continuity planning.

ECG recognizes that the cost for the security is for Country Energy as a whole and not simply CEG. CEG has not advised ECG of its share of the total cost. ECG therefore

[135] CEG email, Issue 5.7, 10 August 2004.
[136] CEG email, Issue 5.7, 10 August 2004.
[137] CEG email, Issue 5.7, 10 August 2004.
[138] CEG email, Issue 5.7, 10 August 2004.

considers that the measures proposed above are reasonable and that it would have an impact on the overall cost.

**Summary –Network Operations and Maintenance**

As discussed in Section 9.1.1, the efficient cost for 2003 is $934,000 and the cost for 2004 is $969,000. This is an increase of $35,000, which is equivalent to a 4% increase. In addition, as shown in Table 9-2, the expenditure for the period January to June 2005 is $499,000, which means for the full year 2005 the total cost is $998,000. As shown in the same table the total cost for the calendar year 2005 is the same as for the financial year 2005/06.

This means that the cost has increased by $35,000 from 2003 to 2004 and an additional $15,000 from 2004 to 2005.

ECG believes that it is probable that the two factors detailed above and the increase in customer numbers would contribute to the increased cost. ECG therefore considers the costs for 2004 and 2005 are in accordance with the Code

**Direct Gas Network Management**

As discussed in Section 9.1.1, the efficient cost for 2003 is $400,000. This cost has increased to $447,000 in 2004 and $448,000 for 2005. This is an increase of 12% from 2003 to 2004.

CEG advises that one of the main reasons for the cost increase is additional compliance requirements imposed by the Department of Energy, Utilities and Sustainability. CEG is now required to collect and report reliability and operating statistics to the Department.

CEG has not provided any quantitative information regarding the cost impact on the additional compliance requirement. However, ECG notes that the Direct Gas Network Management area has appointed two full time business support employees whose roles encompass compliance with these extra obligations.

ECG is unable to quantify the additional cost increase but believes that there is sufficient justification that there will be a cost increase in the Direct Gas Network Management due to compliance requirements.

ECG therefore considers the 2004 and 2005 costs to be efficient within the meaning of the Code.

**Efficiency Factor**

CEG indicated in the AAI 2003 that given the forecast increase in customer numbers, the operating and maintenance expenditure represents a reduction in costs over the forecast period.

ECG considers that businesses through improvement processes and enhancement in IT systems will achieve productivity improvement. In considering what an appropriate efficiency improvement level is for CEG, ECG has considered the data available in the Australian Bureau of Statistics. The multifactor productivity for the Electricity, Gas and Water sector was 1.8% per annum for the period 1993/94 to 1998/99 which was a full cycle[139]. In the three years following 1998/99 it has averaged -2.7% per annum over only part of the cycle[140]. As the recent data represents only part of the cycle, it must be used with some caution. However, the trend has some significance. It provides evidence that the major productivity gains by the gas industry in recent years have slowed. Nevertheless some factors specific to CEG's situation need to be considered.

[139] Australian Bureau of Statistics
[140] Productivity Commission

ECG believes that with the implementation of IT systems and process improvement, it can be expected that CEG will achieve some productivity improvement. In addition the mains rehabilitation planned for the forecast period will also reduce the amount of reactive maintenance carried out. Accordingly ECG proposes that a productivity improvement of 1.5% per annum be factored in to CEG's allowable network O&M costs. This is the same efficiency factor that was recommended for AGL Gas Networks, which is also implementing a number of systems improvements and significant mains rehabilitation.

ECG also believes that it is appropriate to recognize that the O&M will be impacted by customer numbers and increase in the gas consumption. ECG has therefore proposed an increase in the O&M in the ratio of 50% of the percentage increase in customer number and load.

### 9.1.2 Marketing Expenditure

Marketing costs include the cost of CEG's promotional program, including spending to promote the connection of new properties to the network and to increase the number of gas appliances at existing connections. CEG has proposed marketing expenditure of $140,000 (Real 2003/04) for each year of the new Access Arrangement period (equivalent to $146,471(Real 2005/06)). CEG advises that the major marketing focus is to sign up more commercial and industrial customers and to encourage greater use of gas appliances by those already connected to the network. It provided details of marketing incentives expenditure in an email[141].

[This section is considered confidential.]

CEG has also made provision for Gas Awareness activities of [Confidential] per annum. The objective is to conduct such activities at least every 18 months or when a request is made by an interested party. The activities are focussed at organizations such as local councils, emergency services, machinery operators, plumbers and other utilities. Members of the public are also able to attend. These sessions seek to increase the level of awareness of CEG's gas network assets. The areas covered include:

- Procedures to be followed when working within the network.
- Asset location processes.
- The consequences of interfering with the gas assets.
- Emergency management procedures.

CEG has confirmed that the marketing incentives paid to its retail arm are available to any retailer who might wish to offer services in the Wagga Wagga network area[142]. It has also advised that the assumptions regarding take-up of incentives have been based on experience elsewhere in its network[143].

[This section is considered confidential.]

[141] CEG email Issue 5.22, dated 8 November 2004.
[142] CEG email dated 24 November 2004.
[143] CEG email dated 24 November 2004.

The budget for Gas Awareness Activities is considered prudent expenditure in view of the major potential cost of incidents of third party damage to network assets and the public safety benefits.

However whilst ECG believes that the incentive payment per customer and the other programs are prudent, it also notes that there has been a significant increase in marketing cost from 2003 of $102,000 to $146,000 in 2004. ECG considers that the cost difference would have arisen out of the assumption for the number of customers for the incentive payment and the amount paid to each customer.

From the information provided by CEG[144] on increases in customer numbers for this period, ECG has derived that there is on average an increase of 106 customers[145] (net of disconnection) per annum. In Table 8-10, the number of new customers is 147 (net of disconnection). As the marketing cost for 2003[146] is only $102,000 (Real 2005/06) for 147 customers versus $146,471 (Real 2005/06) for 106 customers in 2004 ECG considers that the forecast cost would not be considered efficient in accordance with the Code.

ECG therefore considers that an efficient expenditure would be $102,000 and a nominal allowance of $10,000 for ad hoc programs.

Accordingly ECG considers that the marketing expenditure to be consistent with that of a prudent operator, operating efficiently in accordance with clause 8.37 of the Gas Code is $112,000.

### 9.1.3 Corporate Allocation

As shown in Table 9-2, CEG's Corporate Allocation for the period January 2004 to June 2010 is $607,000 p.a.

As discussed in section 8.3.2, Corporate Allocation includes CEG's corporate costs which have been allocated to the network. The Corporate Allocation costs include billing, accounts payable, credit control, call centres, emergency response, finance and accounting, payroll, business development, property management, customer relations and human resources.

ECG has concluded in section 8.3.2 that the cost of $511,000 for 2003 is efficient. In coming to that conclusion, ECG has assumed the allocation methodology developed by PWC was applied to the 2003 cost and will be used to allocate costs for the forthcoming period.

CEG has not provided any additional information to show why there is an increase in the Corporate Allocation in this period. As such, ECG considers that the efficient level of $511,000 for 2003 should be also the efficient level for the period January 2004 to June 2010.

### 9.1.4 Regulatory Costs

As shown in Table 9-2, CEG has included a regulatory cost of $52,000 in the AAI 2003 submission. Regulatory costs include the costs of preparing, submitting and negotiating the Access Arrangement with the Tribunal, activities in relation to CEG's gas distribution licence, regulatory compliance and generally managing the interface with the Tribunal.

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[144] Load Forecast Report prepared by Infrastructure and Regulation Services December 2003

[145] As gross customer numbers are unknown, net numbers have been used for comparison purposes assuming similar disconnection rates.

[146] 2003 has been used as this was the efficient expenditure as concluded in section 8.3.3

CEG advises that the costs have been forecast on an average annual basis, although in practice regulatory costs tend to peak in the last two years of the regulatory period when Access Arrangement documentation for the next period undergoes revision.

ECG believes that the regulatory cost would generally cover the following:

- The time spent by specialist regulatory staff.
- The time spent by senior management.
- The cost of legal advice.
- The cost of consultancy services.

ECG considers that the annual level of regulatory costs proposed by CEG for the new Access Arrangement period of $52,000 per annum is reasonable considering that the cost of consultancy and legal advice would exceed this amount. It is also worth noting that AGLGN in its AAI 2003 submitted a cost of $2,700,000 for preparing its Access Arrangement submission. ECG therefore considers that CEG's cost of $52,000 is reasonable for a prudent operator, acting efficiently in accordance with the Gas Code.

### 9.1.5 Full Retail Contestability (FRC)

As shown in Table 9-2, ECG notes that for the forecast period from January 2004 to July 2010, CEG has not submitted any cost for FRC.

Whilst it is not explicitly stated, this cost may have been included in the Operating and Maintenance expenditure.

In the absence of any other information, ECG is unable to comment further on this item.

### 9.1.6 Service Standard Administration

As shown in Table 9-2, CEG advises that its cost for Service Standard Administration is $21,000 per annum. CEG has shown that that it will incur this cost in January 2005.

In its AAI 2003, CEG indicates that service standard includes the general management and administration of customer service standards for gas distribution as proposed by the Tribunal. An example of the new requirement is that customers have to be notified by the gas distributor for planned interruptions.

ECG acknowledges that the new customer service standards are a new requirement for CEG. CEG's cost of $21,000 is approximately the cost of an administration person to do this work. ECG therefore considers that the cost is reasonable and would meet the requirements of the Code.

## 9.2 RECOMMENDATIONS

Based on the conclusions reached above, ECG has calculated the recommended costs. Table 9-5 sets out the recommended non capital expenditure for the period January 2004 to July 2010.

**Table 9-5 Non Capital Expenditure 2005 to 2010**
**(Real $ thousand 2005/06)**

| | 2004 | Jan – June 2005 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | Totals |
|---|---|---|---|---|---|---|---|---|
| **Network O&M** | 956 | 492 | 987 | 992 | 990 | 989 | 986 | **6,392** |
| **Marketing** | 112 | 56 | 112 | 112 | 112 | 112 | 112 | **728** |
| **Direct Network Gas Management** | 441 | 221 | 441 | 446 | 444 | 444 | 443 | **2,880** |
| **Corporate Allocation** | 511 | 256 | 511 | 511 | 511 | 511 | 511 | **3,322** |
| **FRC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| **Regulatory Costs** | 0 | 26 | 52 | 52 | 52 | 52 | 52 | **286** |
| **Service Standards Administration** | 0 | 10 | 21 | 21 | 21 | 21 | 21 | **115** |
| **Total** | **2,020** | **1,060** | **2,124** | **2,134** | **2,130** | **2,129** | **2,125** | **13,723** |

# Appendices

# Appendix 1

## EXPENDITURE AUTHORITY AND REVIEW LEVELS

[This section is considered confidential.]

# Appendix 2

# Other Non Capital Expenditure

### Unaccounted for Gas (UAG)

UAG is the difference between the quantity of gas injected into the network and the total quantity withdrawn from the network over a given period. There are a number of factors that affect the quantity of UAG in a gas network, including metering accuracy, timing of meter reading and leakages through the system.

Whilst UAG is usually claimed as a non capital expenditure, CEG has not included any expenditure for UAG into the non capital costs. CEG advises that UAG has been considered as part of the MMA study. As such, ECG has prepared this section to assist the Tribunal in its considerations.

In its Final Decision for the previous Access Arrangement period the Tribunal required that:

- A defined percentage be added to the volume of gas withdrawn from delivery points in order to calculate the volume of gas upon which tariffs will be set.
- The allowable level of UAG be set at 2.5% of network gas throughput.
- The allowable level of UAG be set at 0.76% for contract customers and 4.45% for volume customers.

This approach was designed to provide CEG with an incentive to reduce the level of UAG in the network since any UAG in excess of the allowable levels would be a cost to CEG but the company would retain the financial benefit if it were to achieve a lower level of UAG.

Details of UAG for the years 2000/01 to 2003/04 are set in the table below.

**Details of Unaccounted for Gas 2000-01 to 2003-04**

| Year | Actual UAG (%) | UAG Allowed (%) |
|---|---|---|
| 2000/01 | 5.55 | 2.5 |
| 2001/02 | 7.10 | 2.5 |
| 2002/03 | 4.84 | 2.5 |
| 2003/04 | n.a. | 2.5 |

The percentage of UAG in the current Access Arrangement period has exceeded the allowable levels by a wide margin. CEG has expressed the view that the percentages set for the period were unachievable. Moreover, rehabilitation and replacement of the older parts of CEG's network did not occur at the anticipated rate during the current Access Arrangement Period because resources were diverted to other capital projects. The decision by CEG to divert resources away from mains rehabilitation was a business decision, taken in knowledge of the implications for the company. The business decision to take advantage of the housing boom to increase the number of new customers will benefit all of CEG's customers through economies of scale. Failure to take advantage of the opportunity at the time would have lost those new customers for at least many years and in many cases, forever. On the other hand the decision has resulted in a delay in the reduction of UAG through mains rehabilitation.

CEG has provided ECG with a copy of its Ten Year Capital Works Program for the period 2001/02 to 2010/11. ECG notes that mains rehabilitation work and associated pressure increases account for a major part of that program which has a forecast cost in excess of $8 million. Implementation of works recommended by ECG in 7.3.1 will achieve a reduction in the level of UAG. However ECG has not been provided with any information about the extent of leakage in particular areas which would be essential to assessing a prudent program to mitigate the high UAG problem.

**Government Levies**

In its Final Decision 1999, the Tribunal allowed $96 -$100 annually for this item but noted that increased government levies were anticipated. Accordingly a pass-through mechanism allowing any additional levies was included in the 1999 Final Decision. The actual costs incurred for CEG's Licence (Authorisation) Fee were $66,400 in 2001/02 and $48,100 in 2002/03[147]. No figure has been provided for 2003/04.

ECG considers these costs to be reasonable for a prudent operator operating efficiently in accordance with the Gas Code.

CEG has forecast[148] that $50,000 per annum (in 2003/04 dollars) will be payable for its Licence (Authorisation) Fee in each year of the new Access Arrangement period. This is paid to the NSW Government which seeks to recover the costs it incurs in fulfilling its statutory obligations associated with CEG's Wagga Wagga gas operation. This estimate is considered reasonable, bearing in mind recent fees payable.

ECG notes that CEG discussed an estimated Authorisation Fee in its Access Arrangement Information but did not make provision for the cost in its table of forecast costs, reproduced in Table 9-1.

[147] CEG Email Issue 5.14, 20 October 2004
[148] CEG Email Issue 5.14, 20 October 2004

# Appendix 3

# Conversion Factors

Inflation Factors provided by the Tribunal

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 1/1/05 to 30/6/05 | 2005-06 |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| **Capex(incl GST)** | 1.47% | 4.48% | 4.38% | 3.00% | 2.77% | 2.22% | 1.10% | 2.22% |
| | | | | | | | | |
| **Nominal $ to 2005/06** | | | | | | | | |
| **Capex Conversion Factor** | 1.2195 | 1.1672 | 1.1182 | 1.0856 | 1.0564 | 1.0334 | 1.0222 | 1.0000 |

Inflation Factors provided by CEG (Table 6.2 in the report)

| | | | | | |
|---|---|---|---|---|---|
| **CEG inflation** | 1.41% | 3.47% | 5.06% | 3.03% | 2.93% |
| **CEG conversion factor from nominal to 2003 $** | 1.1358 | 1.12 | 1.0824 | 1.0303 | 1 |

Calculation of Conversion Factors to convert CEG's 1999 -2003 Expenditure in 2003 $ to 2005/06 $ by "Capex conversion Factor "/ "CEG conversion factor from nominal to 2003 $"

Conversion factor from 2003 $ to 2005/06 $

| | | | | | |
|---|---|---|---|---|---|
| **Conversion factor** | 1.07368054 | 1.042139 | 1.03309131 | 1.053721 | 1.056387 |

Table 6-3 New Facilties Investment (Real $ thousand 2003 )(Table 4.1 in AAI 2003)

| Calendar year | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|
| **Asset replacement & refurbishment** | | | | | | |
| **- pipes** | 251 | 373 | 271 | 147 | 250 | **1,292** |
| **- meters** | 295 | 476 | 319 | 136 | 83 | **1,309** |
| **Growth Related** | 1,400 | 1,845 | 1,380 | 1,491 | 1,087 | **7,203** |
| **Non-system assets, FRC** | 0 | 46 | 383 | 352 | 465 | **1,246** |
| **Southern Gate Station** | 0 | 840 | 1064 | 116 | 23 | **2,043** |
| **Actual Capital Expenditure** | **1,946** | **3,580** | **3,416** | **2,242** | **1,908** | **13,092** |

From Table 6-3 New Facilities Investment (Real $ thousand 2006/07)

| Calendar year | 1999 | 2000 | 2001 | 2002 | 2003 (est) | Total |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| **Asset replacement & refurbishment** | | | | | | |
| **- pipes** | 269 | 389 | 280 | 155 | 264 | **1357** |
| **- meters** | 317 | 496 | 330 | 143 | 88 | **1373** |
| **Growth Related** | 1503 | 1923 | 1426 | 1571 | 1148 | **7571** |
| **Non-system assets, FRC** | 0 | 48 | 396 | 371 | 491 | **1306** |
| **Southern Gate Station** | 0 | 875 | 1099 | 122 | 24 | **2121** |
| **Actual Capital Expenditure** | **2089** | **3731** | **3530** | **2362** | **2016** | **13728** |

Forecast Capital Expenditure Real $ thousand 1999 (Table 6-3)

| | | | | | | |
|---|---|---|---|---|---|---|
| **Forecast Capital Expenditure** | 2,500 | 1,363 | 1,373 | 1,164 | 923 | 7,323 |

Forecast Capital Expenditure Real $ thousand 1999 multiply by factor 1.2195 from " Capex conversion factor"

Forecast Capital Expenditure Real $ thousand 2005/06

| | | | | | | |
|---|---|---|---|---|---|---|
| **Forecast Capital Expenditure** | 3049 | 1662 | 1674 | 1419 | 1126 | 8930 |