Utility Regulator
ELECTRICITY GAS WATER

GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016

Final Determination

20 December 2013



About the Utility Regulator

The Utility Regulator is the independent non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries, to promote the short and long-term interests of consumers.

We are not a policy-making department of government, but we make sure that the energy and water utility industries in Northern Ireland are regulated and developed within ministerial policy as set out in our statutory duties.

We are governed by a Board of Directors and are accountable to the Northern Ireland Assembly through financial and annual reporting obligations.

We are based at Queens House in the centre of Belfast. The Chief Executive leads a management team of directors representing each of the key functional areas in the organisation: Corporate Affairs; Electricity; Gas; Retail and Social; and Water. The staff team includes economists, engineers, accountants, utility specialists, legal advisors and administration professionals.

Our Mission	Value and sustainability in energy and water.
Our Vision	We will make a difference for consumers by listening, innovating and leading.

Our Values

Be a best practice regulator: transparent, consistent, proportional, accountable, and targeted.

Be a united team.

Be collaborative and co-operative.

Be professional.

Listen and explain.

Make a difference.

Act with integrity.

Abstract

We are publishing our price control proposals for the gas distribution companies, Phoenix Natural Gas Ltd (PNGL) and firmus energy (FE), for the period 2014-16. The price control sets out a package of measures to continue the efficient growth of the gas industry in NI through building more pipelines and increased connections.

Our determination sets out the amount that the companies shall have to run their businesses and invest in the gas network. The key decisions for both companies are: operating and capital expenditure allowances will be lower than requested but largely consistent with historic costs, the setting of challenging targets for new gas pipelines and connections and the proposed rate of return to remain at 7.5% for the duration of the price control. Our price control proposals will result in reduced costs to customers.

Audience

Industry, consumers & statutory bodies.

Consumer impact

The determination results in a reduction in current distribution charges for the average PNGL domestic customer of around £23 per annum. For industrial and commercial (I&C) customers, particularly large ones, the reduction will be greater given their higher consumption levels.

For FE domestic customers the reduction in distribution charges is around £50 per annum. For I&C customers, particular large ones, the reduction will be greater given their higher consumption levels.

Distribution charges make up around 35% of the total domestic customer bill.

Our final determination sets targets for an additional 43,334 customers to connect to gas and allows 344km of additional gas pipelines to be laid. This will ensure even more customers can enjoy the benefits of natural gas.

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GLOSSARY

£	Pound sterling
A+M+PR mechanism	Advertising, marketing and PR mechanism
ADP	Additional Development Plan
ARW	Airport Road West
BIS	Department for Business, Innovation and Skills
BGE	Bord Gais Eireann (the owner of FE)
capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CEO	Chief Executive Officer
CC or Commission	Competition Commission
CO_2	Carbon Dioxide
CO_2e	Carbon dioxide equivalent, i.e. the equivalent amount of CO_2 that would have the same global warming potential as a given greenhouse gas emission
DAV	Depreciated Asset Value, the depreciated rolled forward value of capex
DETI	Department of Enterprise, Trade and Industry
FCO	First call operative
FE	firmus Energy
FOIA	Freedom of Information Act
FTEs	Full time equivalents
GB	Great Britain
GD14	This is the forthcoming price control for both PNGL and FE, covering calendar years 2014, 2015 and 2016
GD17	The price control for both PNGL and FE, which will follow GD14 and is expected to cover calendar years 2017 to 2021
GDNs	Gas Distribution Networks
GDPCR	Gas Distribution Price Control Review. The GDPCR 2007-2013 distribution price control was undertaken by Ofgem and directly pre-ceded the RIIO-GD1 price control.
GIS	Geographical Information System
HMRC	Her Majesty's Revenue and Customs
I&C	Industrial and commercial
IFRS	International Financial Reporting Standards
IME3	The European Union's third internal energy package
IT	Information technology
JRG	Joint Regulatory Group
MEAV	Modern Equivalent Asset Valuation
NI	Northern Ireland
NICs	National Insurance Contributions
NIE	Northern Ireland Electricity
NIHE	Northern Ireland Housing Executive

NISEP	Northern Ireland Sustainable Energy Programme
NPV	Net Present Value
OAV	Opening Asset Value
OBR	Office for Budget Responsibility
ONS	Office for National Statistics
OO	Owner Occupier (i.e. a privately owned domestic property, either occupied by the owner or rented to a third party)
opex	Operating expenditure
PAS55	The British Standards Institution's (BSI) "Publicly Available Specification" for the optimised management of physical assets
PCR02	The immediate preceding price control for FE covering calendar years 2009 through to 2013
PC03	The price control for PNGL preceding PNGL12 covering calendar years 2007 through to 2011
PES	Phoenix Energy Services
PNGL	Phoenix Natural Gas Limited
PNGL12	The immediate preceding price control for PNGL, covering calendar years 2012 and 2013
PPI	Producer Price Inflation
ppt	Pence per therm – herein used to refer to the conveyance tariff charged by PNGL and FE per therm of gas (for transportation through their respective networks)
Price Base	All monetary figures presented herein, unless otherwise stated, have been rebased using the Retail Price Index (RPI). For PNGL the RPI is as at September 2012 and for FE it is the average for 2012 (as per their respective licences)
PSL	Phoenix Supply Limited (now known as Airtricity Gas Supply (NI) Ltd)
RAB	Regulatory Asset Base
RAV	Regulatory Asset Value
RCM	Reliability-centred Maintenance
RIIO-GD1	This is the first gas distribution price control by OFGEM under the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The price control will be set for an eight-year period from 1 April 2013 to 31 March 2021
RPI	Retail Price Index
SIC	Small industrial and commercial
SWRs	Supplier Work Requests
tCO_2	Tonnes of Carbon Dioxide
tCO_2e	Tonnes of Carbon Dioxide equivalent, i.e. the equivalent amount of CO_2 that would have the same global warming potential as a given greenhouse gas emission
totex	Total expenditure (i.e. capex plus opex)
tpa	Therms per annum – a commonly used measure of gas consumption
TRV	Total Regulatory Value, the DAV plus any incentive adjustments including the profile adjustment. PNGL and FE receive an allowed annual return on TRV
UK	United Kingdom

UR	Utility Regulator
WACC	Weighted Average Cost of Capital, the return allowed on the TRV
WCA	Working Capital Allowances

1 EXECUTIVE SUMMARY

Introduction

1.1 There are two gas distribution licence holders in Northern Ireland (NI) – Phoenix Natural Gas Limited (PNGL) and firmus Energy (Distribution) Limited (FE).

1.2 The purpose of the price control is to put in place a package of measures to challenge PNGL and FE to move the industry forward over the next three years in line with our statutory duties. We do this through cost allowances, incentive mechanisms and targets. The aim of this price control is to deliver a gas industry with more connections and more pipeline network to extend the benefits of gas to more customers. The package encourages the industry to innovate to achieve more connections and to continue to find efficiencies to ensure PNGL and FE remain among the most efficient operators in the UK.

1.3 A fundamental part of the price control is determining how much the two licence holders can charge for the transportation of gas through their networks. The current price controls for both PNGL and FE expire on 31 December 2013 and this document sets out our final decision for the price controls to apply from the beginning of 2014.

1.4 Our consultation on the draft determination[1] for PNGL and FE closed on 20 September 2013. We received seven responses to the consultation.

1.5 The most important points made in each of the responses, and our response in turn to these, are provided in Appendix 5 of this document.

1.6 In formulating our final decisions we have fully and carefully considered each of the responses as well as any new information submitted to us. We have assessed the responses in the light of our statutory duties. As a result, we have adjusted a number of allowances as discussed in the body of this document and in appendix 5.

1.7 Since publication of the draft determination, we have had considerable engagement with the GDNs and stakeholders. As well as several meetings and calls with the GDNs, consideration of submission of further evidence and refinement of our modelling, we also held a stakeholder event on 6 September 2013 to present on the price control and to provide an opportunity for questioning and discussion.

Our Statutory Duties

1.8 A full discussion of our statutory duties is set out in Section 3. The paragraphs below summarise the main points.

1.9 Our principal objective is set out in Article 14 of the Energy (Northern Ireland) Order 2003 ('the Energy Order'). This requires us, in carrying out our gas functions, to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in NI, and to do so consistently with our fulfilment of the objectives set out at Article 40 (a) to (h) of the Gas Directive[2].

1.10 In meeting our principal objective, we must also have regard to a number of other considerations including:

[1] Price Control for Northern Ireland's Gas Distribution Networks Consultation Paper: 16 July 2013 http://www.uregni.gov.uk/uploads/publications/GD14_Final.pdf

[2] Directive 2009/73/EC of the European Parliament and the Council of 13 July concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC. Article 40 includes the objective to protect consumers.

- the need to ensure a high level of protection of the interests of consumers of gas; and
- the need to secure that licence holders are able to finance those activities which are subject to relevant obligations[3].

1.11 Consequently, in developing our determination and in promoting the development and maintenance of the gas industry, we have strived to secure the most efficient outcome in the interests of consumers which also ensures that the companies will be able to finance their licensed activities.

Summary of Approach

1.12 We determine price controls for the two companies by assessing an efficient level of operating costs and capital expenditure to run their businesses and a package of incentives and targets to encourage the continued development of gas within NI.

1.13 This price control will run for three years from 2014 to 2016 as discussed in the draft determination. FE noted in its response to the draft determination that three years is counter to the approach of Ofgem which has set prices for eight years. As we explained in the draft determination, we have made the decision that this will be a three year price control to minimise the need for re-openers and to align with the end of the period (December 2016) for which the cost of capital for both PNGL and FE is fixed at 7.5%. Additionally, this enables us to establish and agree more robust cost reporting procedures for the following price control.

1.14 To assess operating costs (opex), we have undertaken a detailed assessment and review of the larger cost items taking into account the current level of expenditure, the impact as a result of changes in outputs and, where appropriate, benchmarking against comparable organisations.

1.15 We have undertaken a detailed assessment of capital expenditure (capex) proposals in conjunction with our engineering consultants, Rune Associates. This has included a review of existing market rates and benchmarking to identify an efficient level of expenditure.

1.16 We have reviewed our assumptions on efficiency targets and made some adjustments for real price effects.

1.17 We have also reviewed our volume assumptions for FE.

1.18 Each of the companies has an existing asset base – the Total Regulatory Value (TRV). For PNGL this comprises of four elements:

- investment in physical assets;
- under-recoveries of revenue;
- unspent allowances; and
- deferred revenue (the profile adjustment).

1.19 The TRV of FE includes just the first and last of these items. Detailed discussion of the items comprising the TRV of the two companies is provided in section 10.

1.20 We have assessed the value of the TRV as at 31 December 2013. This entails adjusting the TRV for changes in outputs (which affects the capex requirement) e.g. for the number of actual connections.

1.21 The licence of each company enables it to receive a real pre-tax return of 7.5% through to the end of 2016 and as flagged in our draft determination we have not

[3] Those obligations imposed by or under the Energy Order and Part II of the Gas (Northern Ireland) Order 1996 (NI 2) ('the Gas Order').

amended this. As proposed in the draft determination, we are using a weighted average cost of capital (WACC) from 2017 in our model of 4.83% to match the latest Ofgem allowances for GB GDNs (but higher than the Competition Commission's provisional assessment of the cost of capital for Northern Ireland Electricity last month). This is for modelling purposes and does not set a precedent for the rate we will set in GD17. We are minded to use the capital asset pricing model (CAPM) methodology in setting the WACC in GD17. The draft determination set out our initial views on setting the rate of return post 2016 and the responses have commented on this. While a number of issues remain to be considered in more detail in GD17 no new significant risk has been highlighted in the responses and we still view GB GDNs as a starting point in our GD17 analysis. Section 12 sets out some considerations for setting the rate of return post 2016.

1.22 Determination of opex, capex, volumes, allowed returns and the TRV enables us to set tariffs. Tariffs are set on a "levelised" basis, that is, given the cost projections until the end of the recovery period[4], the tariffs are set equal in each year.

1.23 There is a difference between FE and PNGL. For PNGL we set allowed *revenue* each year. For FE we set allowed *tariffs* in each year. The capping of tariffs rather than revenue is more appropriate for a company in the early stage of its development as it provides strong incentives to increase volumes and to develop the gas industry. We will consider for GD17 whether to also set allowances for FE on a revenue capped basis which will reduce its exposure to volume risk.

1.24 In addition, as in the draft determination, we have included two incentive mechanisms to appropriately encourage PNGL and FE to continue the growth of an economic gas industry. The two mechanisms are:

- A connections incentive which rewards the GDNs for connecting owner-occupied (OO) domestic customers. This is a continuation of the incentive mechanism in PNGL12 but updates the economic assessment.
- A properties passed incentive, which incentivises the GDNs to lay infill mains to pass more properties that do not currently have access to natural gas.

1.25 Having determined the revenues to be allowed for PNGL and FE, we have undertaken comprehensive modelling of their financeability, both for GD14 and beyond through to the end of the licence recovery period, including modelling downside scenarios. On the basis of the resulting key financial indicators, the analysis concluded that both PNGL and FE were financeable, that is they would be able to both raise and service any debt or equity as appropriate that may be required to finance their businesses. The details of our financeability modelling are described in chapter 13.

1.26 We note that for any tables shown in this document, totals shown may vary slightly from the sum of the relevant line items due to rounding differences.

Summary of Decisions

Changes from draft determination

1.27 Following responses from stakeholders:

[4] For PNGL the revenue recovery period ends in 2046, however, for FE the revenue recovery period ends in 2035.

- We have increased opex allowances for PNGL by 5% and for FE by 12% (before efficiencies) from the draft determination.
- We have increased capex allowances for PNGL by 1% and for FE by 7% (before efficiencies) from the draft determination
- We have reviewed our efficiency assumptions. We have not altered our proposed 1% productivity efficiency but we are now allowing RPEs of an average of 0.2% per year for opex and 0.3% per year for capex, which results in an average net efficiency target of 0.8% per year for opex and 0.7% per year of capex.

1.28 There has been no material change in our TRV assessment since the draft determination for PNGL which has a TRV of £503.6m (2012 prices). For FE we have updated the calculation which has reduced the TRV from the draft determination from £121.6m to £117.5m.

1.29 We have updated volumes for FE by removing the load for a prospective large customer that may not happen in GD14; this has reduced volumes from the draft determination by about 4.5%.

1.30 We have also updated our connections incentive. We have carefully considered representations from FE and PNGL and as a result we have increased our allowance per additional connection from £480 in the draft determination to £540.

Phoenix Natural Gas Limited

1.31 A summary of our overall determination for PNGL is presented in Table 1 below.

Table 1 – PNGL Determined allowances (post-efficiency), £m

PNGL (2012 Prices), £m, post-efficiency	PNGL Submission				Final Determination				Difference to PNGL Submision	
	2014	2015	2016	Total	2014	2015	2016	Total	Total	%
Opex	16.5	17.0	16.8	50.3	13.6	13.8	13.9	41.4	-8.9	-18%
Capex	13.6	13.7	13.5	40.8	12.1	12.3	12.2	36.6	-4.2	-10%
Total	**30.1**	**30.7**	**30.3**	**91.1**	**25.7**	**26.2**	**26.1**	**78.0**	**-13.1**	**-14%**
The above allowances are fed into our regulatory model, which calculates a revenue requirement to ensure the company recovers the value of the future as well as past investments, plus a return on this investment.										
Allowed revenues	58.1	60.0	61.8	179.8	44.6	46.3	48.0	138.9	-40.9	-23%

Source: PNGL and the Utility Regulator

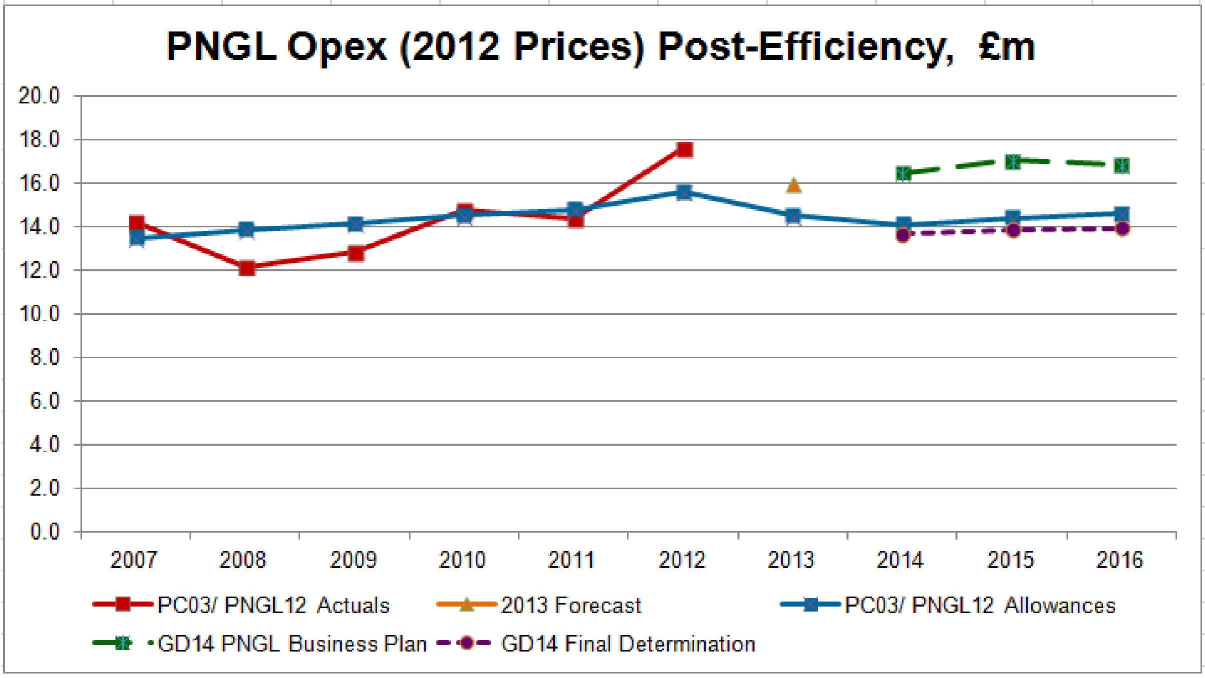
1.32 After careful consideration and analysis we have set a determined capex unit rate allowance for PNGL in line with 2011 actual costs with a reduction for efficiencies. For opex, our determination is less than the allowances requested by PNGL, so that they are more in line with current opex allowances as, in many cases PNGL has not provided adequate justification for the increases.

1.33 It should be noted that our determination is based on a higher connection target for domestic owner occupiers (6,500 per year instead of an average of 4,700 submitted by PNGL). The effect of using a higher connection target gives higher allowances for domestic services and meters as the allowance levels for these cost items are driven by forecast connections.

1.34 Figure 1 shows PNGL's opex actual for 2007-2012, the best available forecast for 2013, their GD14 submission for 2014-2016 and the final post-efficiency allowances detailed in this document[5].

1.35 Figure 2 shows the same information for PNGL's capex.

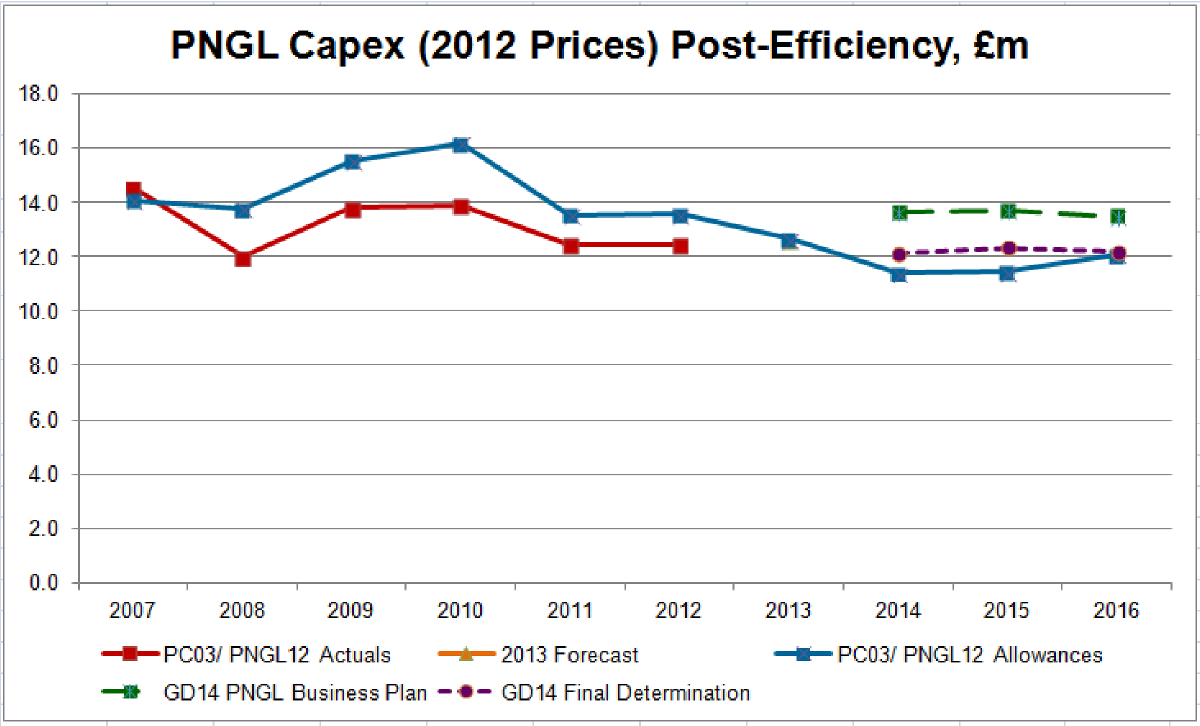
Figure 1 – PNGL operating expenditure submission & final allowances (post-efficiency), £m



Source: PNGL and the Utility Regulator

[5] Note that PNGL's network maintenance and emergency costs within the total opex historic actual costs and forecast costs include an element of Phoenix Energy Services Limited (PES) profit margin which is not allowed in the GD14 determination.

Figure 2 – PNGL capital expenditure submission & final allowances (post-efficiency), £m



Source: PNGL and the Utility Regulator

1.36 Our determination compared to the current PNGL distribution charges (as calculated in accordance with the final determination of the Competition Commission for PNGL12) result in domestic customers paying around £23 less per annum. Compared to the PNGL submission, our determination will result in the average domestic customer paying around £47 less per annum[6].

1.37 For industrial and commercial (I&C) customers, particularly large ones, the difference will be greater given their higher consumption levels.

1.38 The distribution charge makes up around 35% of the total domestic gas bill. Other factors e.g. price of gas will also impact on the total bill.

1.39 The main drivers for the differences above are the application of an updated WACC from 2017 in our model (which is set consistently with that set for GB GDNs) and the increase in forecast volumes compared to PNGL12.

1.40 In line with the Government guidelines for the calculation of greenhouse gas emissions, we have determined the reduction of greenhouse gas emissions for all new connections expected to be achieved during the price control period to be 47,814 tonnes of carbon dioxide equivalent[7]. For all new owner occupier connections expected to be made under the incentive scheme, there will be a reduction of greenhouse gas emissions of 14,895 tonnes of carbon dioxide equivalent during the price control period. See chapter 16 for further details.

1.41 Our final determination sets a total additional connection target of 31,234 and a target for total additional mains laid of 123km for PNGL in GD14.

[6] Note that this will have the biggest impact from 2015 as tariffs have already been set for 2014. The actual impact will depend on other factors such as PNGL's under/over recoveries.
[7] Tonnes of carbon dioxide equivalent is the equivalent amount of CO_2 that would have the same global warming potential as a given greenhouse gas emission.

1.42 The value of the PNGL TRV to 2014 is £503.6m (2012 prices). This is detailed in section 10 of this paper.

Firmus Energy

1.43 A summary of our overall determination for FE is presented in Table 2 below.

Table 2 – FE Determined allowances (post-efficiency), £m

FE (2012 Prices), £m, post-efficiency	FE Submission (revised)				Final Determination				Difference to FE Submision	
	2014	2015	2016	Total	2014	2015	2016	Total	Total	%
Opex	8.3	8.5	8.9	25.7	5.3	5.5	5.7	16.5	-9.2	-36%
Capex	15.1	12.9	11.2	39.1	11.1	9.3	8.3	28.7	-10.4	-27%
Total	**23.4**	**21.3**	**20.0**	**64.8**	**16.4**	**14.8**	**14.0**	**45.2**	**-19.6**	**-30%**
The above allowances are fed into our regulatory model, which calculates a revenue requirement to ensure the company recovers the value of the future as well as past investments, plus a return on this investment.										
Allowed revenues	21.6	22.9	23.6	68.1	17.8	18.4	18.8	55.0	-13.1	-19%

Source: FE and the Utility Regulator

1.44 For capex, our determined unit rate allowances are significantly lower than those requested by FE but more in line with 2011 unit rates with only a slight reduction to ensure the achievement of efficiencies. For opex, our determination is less than the allowances requested by FE, so that they are more in line with current opex allowances, as FE has not provided adequate justification for many of the increases.

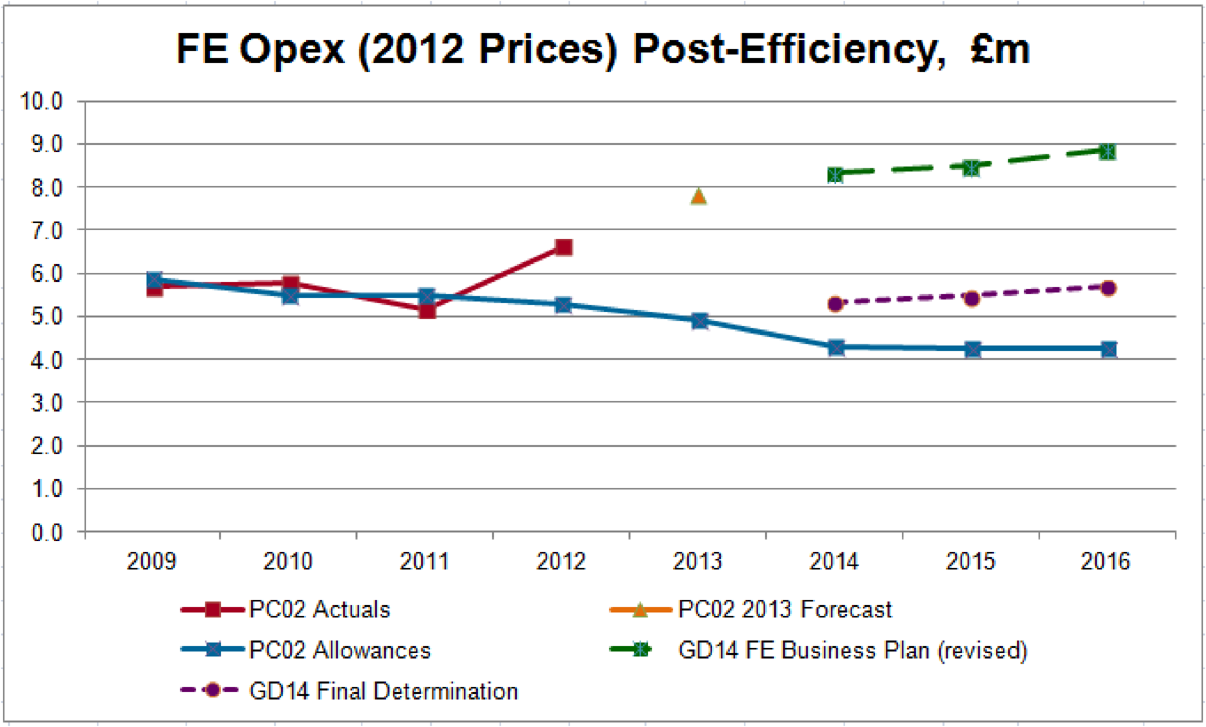
1.45 We have accepted the FE submission on connections. For volumes, we have assumed growth continues in line with the FE submission in domestic and smaller I&C but we do not accept the FE request for reductions in volumes as a result of closures or interruptions. We have also not assumed any large new I&C connections. Our determination amounts to a cumulative volume for the 2014-2016 period of 182.4m therms (as restated)[8] compared to FE proposals of 169.3m therms (as restated).

1.46 Figure 3 shows FE's opex actual for 2009-2012, the best available forecast for 2013, their GD14 submission for 2014-2016 and the final post-efficiency allowances detailed in this document[9].

1.47 Figure 4 shows the same information for FE's capex.

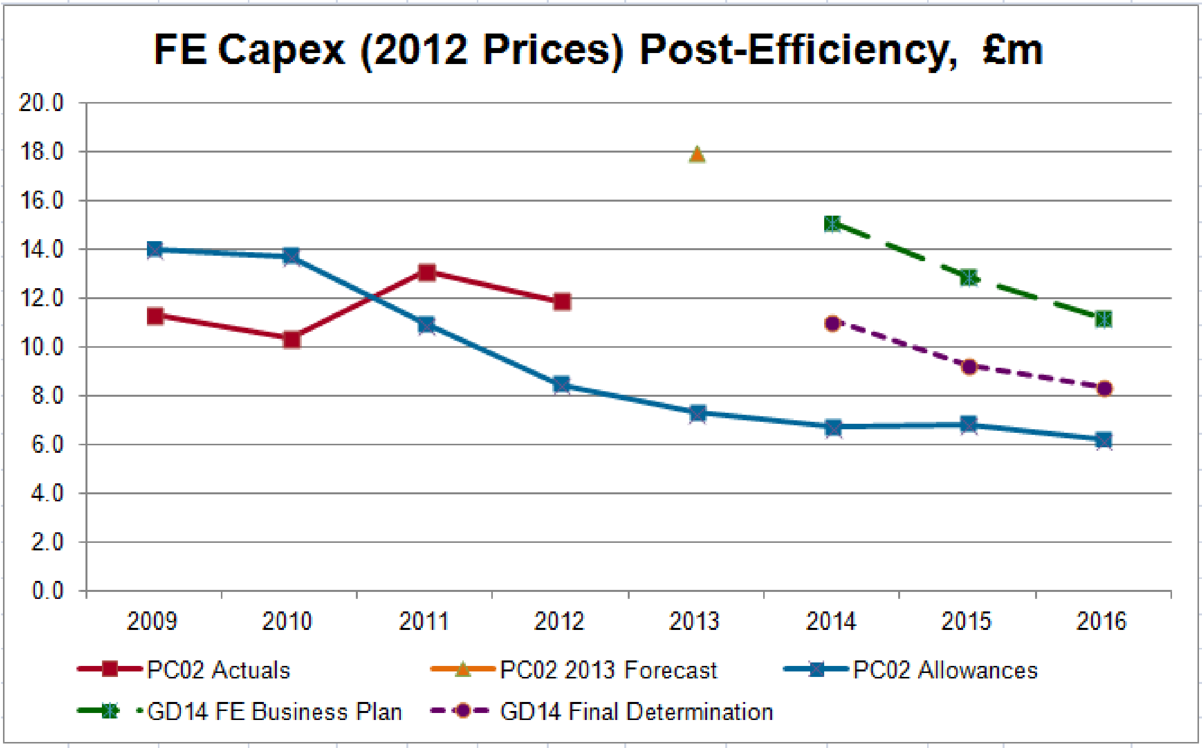
[8] Section 9 provides detail on the restatement of submitted and determined volumes.
[9] Note that FE's historical actual costs include costs which should be removed and allocated to the FE supply businesses (this is discussed in more detail in section 4 of this paper). The historical actual costs are therefore not comparable on a like-for-like basis with its revised submission for 2014-2016 shown in the graph and with our final determination.

Figure 3 – FE operating expenditure submission & final allowances (post efficiency), £m



Source: FE and the Utility Regulator

Figure 4 – FE capital expenditure submission & final allowances (post-efficiency), £m



Source: FE and the Utility Regulator

1.48 Our determination compared to the current FE determined distribution charges will result in domestic customers paying around £50 less per annum. Compared to the FE submission, our determination will result in the average domestic customer paying around £73 less per annum. We would note however that the actual impact on bills may be very different as FE has chosen to price below the regulated charges and future bills will be impacted by these under-recoveries.

1.49 For I&C customers, particular large ones, the difference will be greater given their higher consumption levels.

1.50 The distribution charge makes up around 35% of the total domestic gas bill. Other factors e.g. price of gas will also impact on the total bill.

1.51 The main driver for the difference in these figures is the increase in volumes and the application of an updated WACC from 2017 in our model.

1.52 In line with the Government guidelines for the calculation of greenhouse gas emissions, we have determined the reduction of greenhouse gas emissions for all new connections expected to be achieved during the price control period to be 22,230 tonnes of carbon dioxide equivalent[10]. For all new owner occupier connections expected to be made under the incentive scheme, there will be a reduction of greenhouse gas emissions of 6,606 tonnes of carbon dioxide equivalent. See chapter 16 for further details.

1.53 Our final determination sets a total connection target of 12,100 and a target for total mains laid of 221km for FE in GD14.

[10] Tonnes of carbon dioxide equivalent is the equivalent amount of CO_2 that would have the same global warming potential as a given greenhouse gas emission.

1.54 The value of the FE TRV in 2014 is £117.5m (2012 prices). FE had a cumulative under-recovery of £19.4m at the end of 2012 (2012 prices) based on the difference between actual and determined tariffs. We will approve increases in FE tariffs in future to recover this under-recovery amount. This is set out in more detail in section 10.

Next Steps

1.55 No licence modifications under Article 14 of the Gas Order will be required to implement this price control. The price control can be implemented for both GDNs in reliance on the terms of their existing licences.

1.56 Due to time pressures, we will not publish the regulatory models for the calculation of revenues relating to the GD14 price control together with this final determination. We intend to do so at a later stage.

1.57 The changes outlined in chapter 5 on the policy for domestic meter exchanges (where PNGL will receive no more allowance for exchange of prepay to credit meters and instead recover the costs from the domestic customers) will need to be reflected in the PNGL connection policy. The change of policy will be implemented from 1 April 2014 and we will be working closely with PNGL to ensure the change of policy is implemented by this date.

1.58 In preparation for the GD17 price control, we will consider a revision of the price control timelines. In particular, we will consider options for earlier submission of the GDN's business plans to allow more time for subsequent analysis and stakeholder engagement ahead of the final determination. Related consultations and, where required, licence modifications will be published in due course.

1.59 We also plan to work closely with the GDNs to implement an enhanced, robust and consistent system for cost reporting. This will form a basis for cost comparison and would serve as a source of data for future price controls.

1.60 We expect that a clearly set out timetable, together with improved cost reporting will lead to better quality of submissions and enable an effective and efficient price control process for GD17.

2 INTRODUCTION

Update from Draft Determination

2.1 This document sets out our final decisions. For ease of reading, at the beginning of each section we have highlighted the main changes that we have made since the draft determination.

2.2 We have updated the section on the GD14 price control process with respect to GD14 timelines and lessons learnt which we intend to implement as part of future price controls.

Background

2.3 Our principal objective in carrying out our gas regulatory functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland (NI).[11] As part of our role, we set overall limits on how much companies that own and operate the natural gas networks can charge for use of their pipelines, through a process called price controls.

2.4 There are two gas distribution licence holders in NI - Phoenix Natural Gas Limited (PNGL) and firmus energy (Distribution) Limited (FE). PNGL owns and operates the distribution network in the Greater Belfast and Larne areas. FE owns and operates the distribution network commonly referred to as the 'Ten Towns' and which runs off the North-West and South-North natural gas transmission pipelines.

2.5 The current price controls for both PNGL and FE end in 2013. New price controls therefore must be in place for the beginning of 2014. This final determination paper outlines our determination for the allowed revenues or tariffs (in the case of FE) over the next price control period for both licence holders. This is the first time that we are conducting a parallel price control and results from an explicit intent to align the timing of the two price reviews, which we consulted upon in 2010.

2.6 In this section, we provide broad overviews of the two licence holders and set out further relevant contextual information regarding the present price control process.

Company Overviews

PNGL

2.7 PNGL is the licensed owner and operator of the distribution network in the Greater Belfast Area and Larne, and is the larger of the two gas distribution businesses in NI. The company is responsible for the development of the pipeline network and also for providing a 24/7 operational and transportation service platform to gas suppliers under the rules of the company's network code.

2.8 PNGL was awarded its conveyance licence and commenced operations in September 1996. Currently, the PNGL network extends to over 3,000 kilometres of intermediate, medium and low pressure mains, which distribute natural gas throughout the licence area.

[11] Our duties and the regulatory principles that guide our work are discussed further in chapter 3.

2.9 PNGL manages the development of both the physical network and the market in Greater Belfast. Over 160,000 domestic and business customers have been connected to PNGL's network, while the market continues to grow at approximately 8,000 – 10,000 new customers each year.

FE

2.10 FE is a subsidiary of Bord Gais Eireann (BGE) which has been providing natural gas to customers in the Republic of Ireland for a number of years. FE was awarded its conveyance licence in March 2005 and has since constructed a network consisting of about 750 km of mains pipes across its licence area.

2.11 We note that on December 12 2013 BGE named a consortium led by Centrica (which includes Brookfield Renewable Power, a Canadian renewable investment fund, and iCON Infrastructure) as the preferred bidder for Firmus Energy. Completion is expected in the first half of 2014.

2.12 The FE Ten Towns licence area covers a geographical region that includes Londonderry, Limavady, Coleraine (including Portstewart and Bushmills), Ballymoney, Ballymena (Broughshane), Antrim (including Ballyclare and Templepatrick), Craigavon (including Portadown and Lurgan), Banbridge, Newry (Warrenpoint) and Armagh (Tandragee).

2.13 In the first few years of network development, FE's focus was on connecting the large industrial and commercial companies in each of the towns, such as factories, hospitals, large hotels and universities. Following the connection of these large users, FE's network development is directed towards the connection of small businesses, new-build housing developments, owner occupiers and Northern Ireland Housing Executive (NIHE) properties, where economic in each of the towns. FE has around 19,000 customers connected to its network, and is currently growing at about 3,000 – 4,000 per year.

Price Control Context

Existing price controls: PNGL12 (2012-13) and PCR02 (2009-13)

2.14 In late 2009, we began scoping and planning the work necessary to develop PNGL's price control that would apply following the then effective control, PC03, spanning the period 2007 to 2011. In considering the issues involved, we also assessed the merits of aligning the timing of the price controls of the two NI gas distribution networks (GDNs) and how we might achieve this. The potential options were consulted upon in January 2010.[12] A decision then followed to align the price controls by way of establishing a two-year control for PNGL covering 2012 and 2013, thereby achieving alignment of the two GDNs in 2014.

2.15 We subsequently prepared and presented the new determination (called PNGL12) to PNGL, which was rejected. The determination was therefore referred to the Competition Commission (CC) in March 2012. The CC's inquiry ended on 30 November 2012, and therefore PNGL12 is currently effective (subject to the changes arising from the CC's findings and recommendations) for the two-year price control period ending in 2013.

[12] The Utility Regulator: "Aligning the Price Control Reviews of Northern Ireland's Gas Distribution Networks", January 2010 (http://www.uregni.gov.uk/uploads/publications/NI_GDNs_Price_Control_Alignment_v10_FINAL.pdf)

2.16 FE's current price control runs from 2009 to 2013 and is referred to as PCR02, being the second price control in its history.

Differences between PNGL and FE

2.17 PNGL and FE have certain similarities regarding the nature of their business and the manner in which they are regulated. For example, both GDNs are regulated so that they have sufficient revenues or conveyance charges to enable the recovery of operating costs, capital expenditure and a permitted rate of return (which is set at 7.5% real, pre-tax for both businesses until the end of 2016). In addition, both companies were tasked with the development of new gas distribution networks (i.e. greenfield investments), as previously there was no (or limited) gas infrastructure in their respective licence areas.

2.18 There are however some significant differences between the two licensees. FE is currently at a different stage in its network roll-out. As mentioned above, FE was awarded its licence in 2005, compared to 1996 for PNGL. Also, the FE licence area is larger than PNGL's, but population (and therefore connection) density is much lower.

2.19 In addition, the regulatory treatment of the two GDNs varies in some respects. The key differences are the following:

- ***Form of price control*** - PNGL has a revenue cap, that is, we determine total allowed revenues and PNGL must set tariffs to avoid revenue over-recovery. FE, on the other hand, has a price cap which means that the maximum tariffs are fixed based on determined volumes. The price cap provides an incentive to outperform on volumes as the revenue derived from outperformance can be retained[13].
- ***Levelised charging period*** – given the 'new build' nature of the gas distribution networks, revenue recovery for both companies is profiled over an extended period to reflect the fact that it would take time for volumes to grow to a sustainable level. This is intended to ensure stable long-term prices and effectively delays an element of revenue recovery to later in the licence period. PNGL's levelised charging period is 40 years (extended from 20 years initially and now ending in 2046), while FE's is 30 years (i.e. out to 2035). Tariffs are set to remain broadly the same across the charging period with the result that some allowed revenue is deferred to future years and included in the Total Regulatory Value (TRV) as a 'Profile Adjustment'.
- ***Revenue under-recovery*** – this occurs when prices charged to customers are below the allowed price cap. FE is currently permitted by its licence to recover the unrecovered revenues by future increases in tariffs above determined levels. Under the revenue cap regime now applying to PNGL, unrecovered revenues attract an interest rate below the allowed cost of capital, which incentivises PNGL not to under-recover.
- ***Rolling incentive mechanisms*** – FE has a capex and opex rolling incentive mechanism within its licence, although this is currently 'switched off'. There is no such provision in the PNGL licence, although for capex we have adopted a roller through the retrospective adjustment mechanism, which has the same effect in practice.

2.20 In the present price control we have attempted to ensure as much consistency between the two GDNs as is appropriate and beneficial, while recognising that there

[13] PNGL had also operated under a price cap in the period 1996-2006, when it was at a similar stage of development to FE and therefore the focus was on providing incentives to grow the nascent gas market.

are differences in the operational and business environment of the two companies and therefore their regulation.

The GD14 Price Control

2.21 The alignment of the price controls for the two GDNs has offered us the opportunity (subject to recognising the differences just discussed) to adopt a coordinated approach to the PNGL and FE price controls. The intention is to have a consistent approach to gas distribution across NI and to facilitate benchmarking between the companies to provide downward pressure on costs and the continued pursuit of efficiencies and service enhancements, where these are available. Such "comparative regulation" is widely used, to a beneficial effect, in the rest of the UK.

2.22 The aim that we set out was that the GD14 process would benefit consumers by:

- Providing a strong foundation for the continued and long-term growth of gas distribution networks, delivering service improvements to consumers;
- Challenging the GDNs to improve their efficiency and performance at an achievable and sustainable rate;
- Promoting long term planning by the licensees and secure the continuity of necessary and efficient investment; and
- Ensuring that revenues and prices are set at the minimum levels that are consistent with the efficient operation of the businesses and with delivering the required outputs and investment.

2.23 The price control process commenced with the submission by the GDNs of their business plan (including actual data for previous years), setting out their assessment of the funding necessary to deliver the outcomes specified in the plan. These were scrutinised by our office, following which we issued a draft determination for consultation (published on 16 July 2013) and then, after a public consultation period of nine weeks and detailed consideration of responses, our final determination (which is this document).

2.24 The timetable leading to issuing the GD14 final price control determination is shown in Table 3.

Table 3 – GD14 price control timetable

Key milestones	Date
Consultation paper on our overall approach	3 December 2012
Submission of business plans by GDNs	End December 2012
Update paper on our overall approach	26 March 2013
Stakeholder engagement	April – June 2013
Publication of Draft Price Control Determination for consultation	16 July 2013
Stakeholder engagement during consultation period (incl. stakeholder workshop)	July – September 2013
Submission of responses to consultation on Draft Determination	20 September 2013
Stakeholder engagement prior to publication of Final Determination	October – December 2013
Final Determination published	20 December 2013
GD14 commences	1 January 2014

Source: The Utility Regulator

2.25 We originally intended that the price control submissions be received in September 2012, but we only received them at the end of last year. This has compressed the normal amount of time we have had to analyse the submissions. We intend to ensure future price controls submissions will be provided earlier to allow for a longer process before final determination.

2.26 Overall, our approach to the GD14 price control has been aligned with Ofgem's approach to RIIO-GD1. We consider that, through the consultations on the overall GD14 approach (published on 3 December 2012) and the consultation on the draft price control determination (published on 16 July 2013), through the stakeholder workshop held on 6 September 2013 and through regular meetings with the GDNs, we have provided all stakeholders appropriate opportunities for engagement throughout the price control process. That said, we note that as a result of submissions only being received in late December 2012 the timelines were compressed; we therefore intend to set out proposals for enhanced stakeholder engagement, in particular with consumers and their representatives, for GD17.

3 APPROACH

Update from Draft Determination

3.1 There have been no material changes in this section from the draft determination.

Our Statutory Duties

3.2 Our statutory duties are set out in Article 14 of the Energy Order.

3.3 In accordance with these duties, our principal objective is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in NI, consistent with Article 40 of the Gas Directive.[14] We believe this is best achieved through a regulatory framework that underpins investor confidence that they will receive:

- A fair return on continuing investment; and
- Fair, incentive-based rewards (or penalties) for performance that departs from reasonable evidence-based *ex ante* expectations or, where they can be objectively determined, *ex post* assessments of efficient outcomes.

3.4 In furthering our principal objective, we must also have regard to the interests of gas consumers and their need for a high level of protection. This is not a zero-sum game as it is fundamentally in the consumers' interest also to have an efficient, economic and co-ordinated gas industry. The investor confidence we refer to above is therefore in the interest of consumers.

3.5 We do, however, need to guard against inappropriately excessive returns and unfair rewards/penalties, which could:

- Over-compensate investors, to the direct detriment of consumers; or
- Under-compensate them, thereby damaging investor confidence, ultimately to the detriment of consumers; or
- Undermine the effectiveness of incentives on the companies to strive for better outcomes, which would also be to the detriment of consumers.

3.6 These considerations have guided our work for the GD14 review and have remained at the front of our minds throughout.

Regulatory Principles

3.7 Our statutory duties lead us to some important regulatory principles. Because of the common themes in the duties across economic regulators within the UK, these principles draw from the wider body of principles and practice that have evolved in the UK over the last twenty years or so.

3.8 We subscribe to the overarching principles of better regulation, which are to ensure that:

[14] Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC. Article 40 includes the objective to protect consumers.

- Any burdens we impose on regulated companies are proportionate to the issues they are designed to address;
- In taking decisions and throughout the review, we are accountable to interested parties and to the Government;
- We are consistent and have regard to past decisions;
- We are transparent, which means interested parties can see and challenge the rationale and the evidence basis for material decisions; and
- Regulation is well targeted, which means our decisions are calculated to achieve our statutory duties.

3.9 These principles have important implications, which resonate strongly with our statutory duties.

3.10 We further acknowledge the importance of the regulatory asset base, identified as Total Regulatory Value (TRV) in the gas distribution licences, as an expression of regulatory commitment. This requires us to maintain the integrity of pre-specified mechanisms for rolling forward the TRV wherever investors might reasonably have relied on them prior to making investment or other decisions.

Form of Price Control

Cost allowances

3.11 The price controls for the two companies are set on the basis of attempting to ensure that the businesses are remunerated for efficient operations and investment. This in turn has required us to set allowances for operating expenditure (opex) and capital expenditure (capex) for PNGL and FE in each year of the control period. A full explanation of the rationale behind our opex and capex allowances is set out later in the relevant sections of this paper.

3.12 Our opex and capex allowances are those which we consider efficient for PNGL and FE to deliver the required outputs over the control period. Whilst we intend to scrutinise how the companies actually spend their allowances at the level of individual cost lines (via our annual cost reporting regime), the most important consideration is that we expect PNGL and FE to be able to deliver the necessary outputs whilst keeping within their *overall* cost allowances.

Indexation

3.13 We use the retail price index (RPI) to protect GDNs from inflation. RPI is applied to the TRV in each year. In addition, allowed tariffs (in the case of FE) and allowed revenues (in the case of PNGL) are increased annually by the relevant RPI.

Duration

3.14 Our original intention as documented in our overall approach paper released on 3 December 2012[15] was to have a ‘standard’ five-year price control period. We noted at the time that the duration of a price control is largely a matter of judgement, but felt that this provided a fair balance between the need for allowing the licensees sufficient time to plan and deliver their services, and the requirement for new and

[15] The Utility Regulator: “Price Control for Northern Ireland’s Gas Distribution Networks GD14, Consultation on Our Overall Approach”, 3 December 2012: (http://www.uregni.gov.uk/publications/consultation_into_overall_approach_for_price_controls_of_nis_gas_distributi)

material information about operating and financial conditions to be factored into the allowed revenues or tariffs of the companies.

3.15 We also noted that a five-year price control was conditional upon allowing for a number of 're-openers' within the control period, largely because the information submitted by the GDNs was only received at the end of 2012 and not sufficiently detailed. This could have created undue risks for the company and customers in setting allowances for five years.

3.16 Following the consultation on our overall approach and in response to concerns raised about the use of re-openers, we indicated in our follow-up approach paper published in March 2013[16] that it would be sounder to shorten the duration of GD14 to a three-year control period. This would mean that GD14 would run from 2014 to 2016.

3.17 The reduced price control duration would have certain advantages, primarily it would minimise the need for re-openers. A three-year price control also aligns with the end of the period (December 2016) for which the cost of capital for both PNGL and FE is fixed at 7.5%, thereby enabling us to set a considered cost of capital for the following control, GD17, taking into account the prevailing financial conditions at that time. Moreover, the intervening period can be used to establish and agree more robust information structures and submission procedures ensuring that the GDNs provide transparent and high quality information in a consistent and timely manner.

3.18 We remain of the view that the advantages of a shorter price control outweigh any disadvantages and therefore the present price control covers the calendar years of 2014, 2015 and 2016. Hence the detailed forecasts presented in the subsequent chapters relates to this three-year period. Note, however, that for both PNGL and FE forecasts through to the end of the recovery periods have been used to enable us to set tariffs for GD14 on a levelised basis through to the end of the recovery periods.

3.19 It is our intention that the following price control, GD17, will set prices for five years from 2017 through to 2021. The duration and form of control for GD17 will be consulted on in the future.

[16] The Utility Regulator: "Update on Our Overall Approach for the price controls of NI's gas distribution networks", 26 March 2013: (http://www.uregni.gov.uk/publications/update_on_our_overall_approach_for_the_price_controls_of_nis_gas_distributi)

4 PRICE CONTROL SUBMISSIONS

Introduction

4.1 PNGL and FE are required as a condition of their gas conveyance licence to submit to the Utility Regulator relevant information necessary for us to complete a price control review.

4.2 In late 2012 both companies submitted their projections. This section presents a summary of the information submitted by PNGL and FE, focusing in particular on the resource requirements stated as necessary by the companies to operate and develop their networks over the control period.

4.3 In this section, we show the original opex submission followed by the GDN's revised opex submission. Throughout the remainder of the final determination, we use the revised submission as the GDNs' requested costs

Update from Draft Determination

Phoenix Natural Gas Limited

4.4 PNGL advised that its opex submission included an allocation error which impacted on the insurance and fleet costs requested in 2014, 2015 and 2016 and we have now amended for this.

4.5 In this section, we show PNGL's original opex submission followed by the 'revised' opex submission to correct this allocation error. Throughout the remainder of the final determination, we use the 'revised' submission when we state PNGL's requested costs.

Firmus Energy

4.6 Since the draft determination, we have identified some issues with the FE opex submission. We received information from FE on supply costs after the consultation period ended which highlighted some allocation issues between the FE distribution and supply businesses. It is now apparent that in some cost lines (e.g insurance and office rates) FE allocated all costs to the distribution business in their historic actuals and also in their forecasts for the GD14 period. In other areas (e.g. manpower), FE has heavily weighted costs towards the distribution business.

4.7 We have reviewed each cost line of the FE submission and where possible, we have revised the FE submission by removing costs which we consider should be allocated to the supply businesses.

4.8 In this section, we show FE's original submission followed by their 'revised' submission. Throughout the remainder of the final determination, we use the 'revised' submission when we state FE's requested costs.

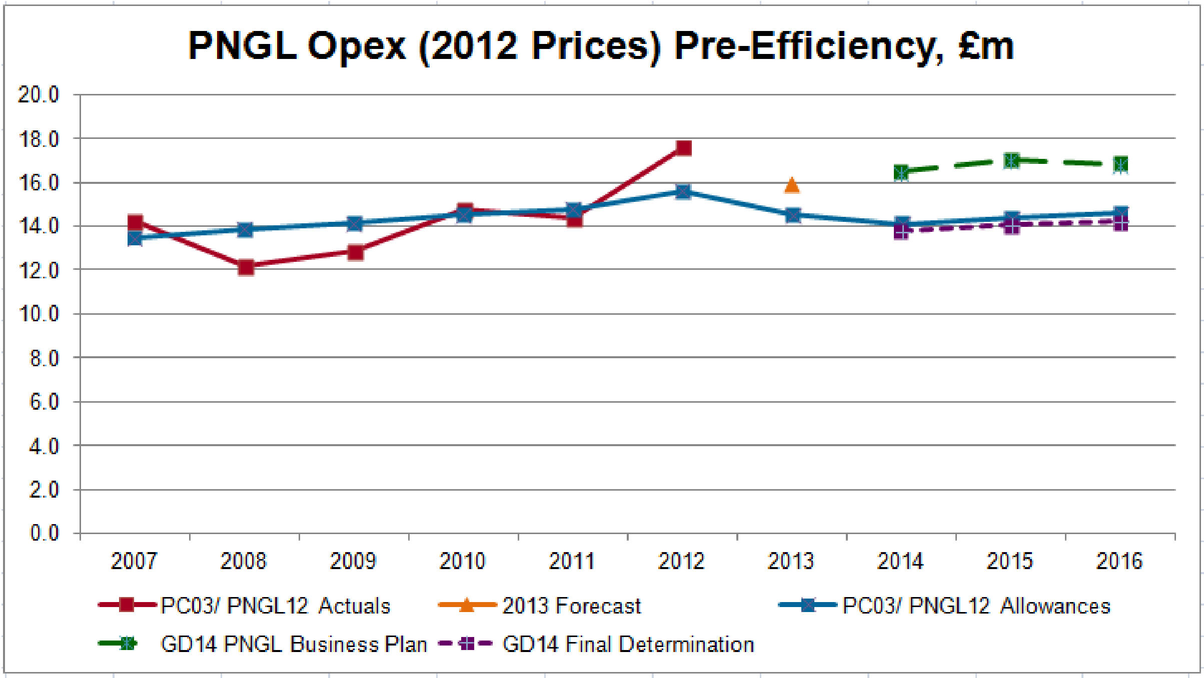
Phoenix Natural Gas Limited

Overview

4.9 Figure 5 below shows a summary of PNGL's opex costs from 2007 to 2012, the forecast outturn for 2013, its requested allowances for GD14 and our final pre-efficiency allowance[17].

4.10 Figure 6 shows the same information for PNGL's capex.

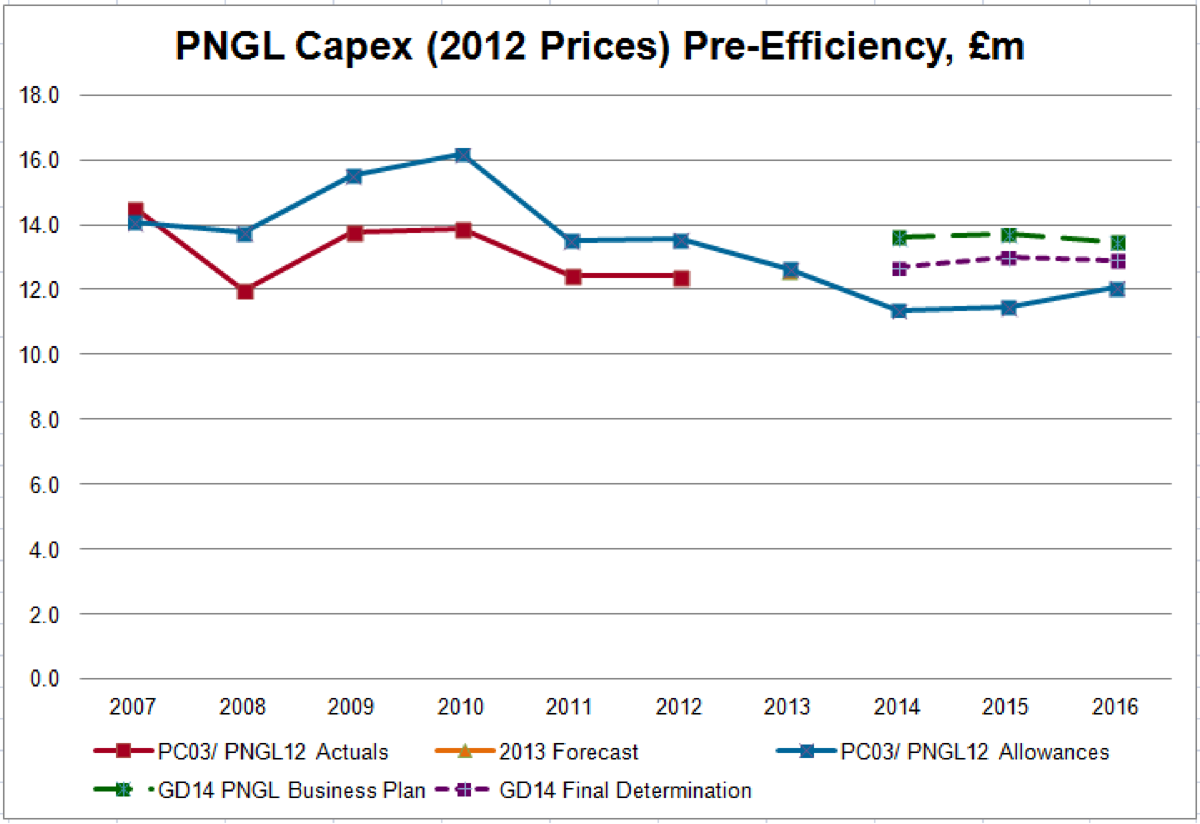
Figure 5 – PNGL operating expenditure (pre-efficiency), £m



Source: PNGL and the Utility Regulator

[17] Note that PNGL's network maintenance and emergency costs within the total opex historic actual costs and forecast costs include an element of PES profit margin which is not allowed in the GD14 determination.

Figure 6 – PNGL capital expenditure (pre-efficiency), £m



Source: PNGL and the Utility Regulator

4.11 Overall, PNGL's capex request is in line with 2011 actual costs with a reduction for efficiencies. In relation to operating expenditure, the graph demonstrates how PNGL costs increased significantly over the PNGL12 period, chiefly as a result of legal and consulting costs awarded from the Competition Commission's decision. The graph also shows that the GD14 requested opex allowances are significantly higher than previous allowances.

Operating Expenditure

4.12 The table below sets out a summary of the overall opex allowances requested by PNGL in their original submission. More detail of the build-up of some of the individual cost lines was also provided, both in the original PNGL submission and following our information requests.

Table 4 – PNGL operating expenditure original submission, £k

Cost item	2014	2015	2016	Total
Advertising, marketing and PR	860	829	789	**2,479**
Billing	214	222	231	**666**
Emergency costs	2,211	2,304	2,400	**6,916**
Entertainment	43	43	43	**128**
Fleet costs	265	266	260	**792**
Human resources	121	117	116	**354**
Incentives	783	724	666	**2,173**
Information technology	305	316	321	**942**
Insurance	1,032	1,059	1,084	**3,175**
Licence fees	128	128	128	**385**
Manpower	5,351	5,454	5,413	**16,218**
Network maintenance	2,438	2,669	2,374	**7,481**
Office costs	544	595	630	**1,769**
Own use gas	17	18	18	**53**
Professional and legal fees	670	633	632	**1,936**
Rates	1,228	1,390	1,457	**4,075**
Stationery	51	52	53	**157**
Telephone and postage	130	140	142	**412**
Travel and subsistence	71	71	71	**213**
Total	**16,464**	**17,032**	**16,827**	**50,324**

Source: PNGL

4.13 The following table shows the PNGL ‘revised’ opex submission, to correct an allocation error that existed in the original submission between the insurance cost line and the fleet cost line.

Table 5 – PNGL operating expenditure 'revised' submission, £k

Cost item		2014	2015	2016	Total
Advertising, marketing and PR		860	829	789	**2,479**
Billing		214	222	231	**666**
Emergency costs		2,211	2,304	2,400	**6,916**
Entertainment		43	43	43	**128**
Fleet costs	Original Request	265	266	260	
	Moved from Insurance Costs	48	48	47	
	Revised Request	**313**	**314**	**307**	**934**
Human resources		121	117	116	**354**
Incentives		783	724	666	**2,173**
Information technology		305	316	321	**942**
Insurance	Original Request	1,032	1,059	1,084	
	Moved to Fleet Costs	-48	-48	-47	
	Revised Request	**984**	**1,012**	**1,037**	**3,033**
Licence fees		128	128	128	**385**
Manpower		5,351	5,454	5,413	**16,218**
Network maintenance		2,438	2,669	2,374	**7,481**
Office costs		544	595	630	**1,769**
Own use gas		17	18	18	**53**
Professional and legal fees		670	633	632	**1,936**
Rates		1,228	1,390	1,457	**4,075**
Stationery		51	52	53	**157**
Telephone and postage		130	140	142	**412**
Travel and subsistence		71	71	71	**213**
Total		**16,464**	**17,032**	**16,827**	**50,324**

Source: PNGL and the Utility Regulator

4.14 Throughout the remainder of the final determination, we use the 'revised' submission when we state PNGL's requested costs.

4.15 In section 5 we examine PNGL's opex claims and allowances in some detail. At an aggregate level, however, PNGL's requested average annual opex allowance is significantly higher than both our determined allowances in PNGL12 (+11.4%) and PNGL's actual cost performance during PC03 i.e. the years 2007-2011, being the period for which we have detailed final audited numbers (+23%).

4.16 The cost lines that are contributing mostly to the increase in the operating expenditure claim are the following:

- Insurance
- Manpower
- Network Maintenance
- Rates.

Capital Expenditure

4.17 The table below summarises the capex allowance requested by PNGL. More detail on some of the individual cost lines was also submitted by PNGL, which is examined and discussed in section 7.

Table 6 – PNGL capital expenditure submission, £k

Cost item	2014	2015	2016	Total
4 bar mains	0	0	0	**0**
Pressure reduction stations	119	119	0	**238**
Feeder Mains	110	121	131	**362**
Infill mains	3,090	3,214	3,314	**9,618**
Domestic services	3,586	3,503	3,401	**10,490**
Domestic meters	1,758	1,730	1,692	**5,179**
I&C services	589	589	589	**1,768**
I&C meters	373	374	374	**1,121**
Other capex (network code, fixtures & fittings, IT)	298	296	250	**844**
Traffic Management Act	2,755	2,791	2,770	**8,317**
Management fee	963	965	950	**2,878**
Total	**13,641**	**13,703**	**13,471**	**40,815**

Source: PNGL

PNGL Connection Assumptions

4.18 PNGL's assumed annual level of incremental connections for the control period is set out below.

Table 7 – PNGL determined new connections (average per year)

Customer category	Annual average connections
Domestic – Owner Occupier (OO)	4,700
Domestic – New Build (NB)	2,533
Domestic – Northern Ireland Housing Executive (NIHE)	1,000
Industrial and Commercial (I&C)	378
Total	**8,611**

Source: PNGL

GD14 Projected Outputs versus PNGL12 and PC03 Outputs

4.19 PNGL also provided information on the level of outputs it plans to deliver over the control period, the main ones being:

- Kilometres of mains laid;
- Number of properties passed; and
- Number of properties connected.

4.20 For illustrative purposes, we set out below the following:

- PNGL's historical performance comparing actual audited accounts for 2007 to 2011 (the latter being the most recent year for which we had detailed audited data at the time of writing) against the PC03 determination with allowances adjusted as foreseen by the retrospective mechanism; and

- PNGL's actual performance in calendar years 2007 to 2011 compared with its allowance requests and forecast outputs for GD14 (i.e. 2014 to 2016).

4.21 The two sets of data are respectively shown in the tables that follow.

Table 8 – PC03 actuals versus PC03 determination (with retrospective adjustments), £k

Cost items	2007	2008	2009	2010	2011	Average	2007	2008	2009	2010	2011	Average
	Actuals 2007-2011						PC03 allowances (retrospectively adjusted)					
Capex, £m	14.5	12	13.8	13.9	12.5	**13.3**	15.7	12	13.4	13.2	12.1	**13.3**
Opex, £m	14.2	12.2	12.8	14.8	14.4	**13.7**	13.1	13.3	13.7	14.8	15.6	**14.1**

Source: PNGL and the Utility Regulator

Table 9 – PC03 actuals versus PNGL GD14 submission, £k

Allowances and outputs	2007	2008	2009	2010	2011	Average 2007-11	2014	2015	2016	Average GD14 submission
	Actuals						PNGL submission			
Capex, £m	14.5	11.9	13.8	13.9	12.5	**13.3**	13.6	13.7	13.5	**13.6**
Opex, £m	14.2	12.2	12.8	14.7	14.4	**13.7**	16.5	17	16.8	**16.8**
Total cost, £m	28.7	24.1	26.6	28.5	26.9	26.9	30.1	30.7	30.3	30.4
Pipe laid, km	80	61	78	73	56	**70**	67	70	73	**70**
Properties passed	8,438	8,027	8,168	9,350	8,074	**8,411**	5,703	5,953	6,153	**5,936**
Connections (domestic)	10,902	7,900	8,118	8,081	9,719	**8,944**	8,778	8,628	8,428	**8,611**
Connections (I&Cs)	532	506	457	455	427	**475**	378	378	378	**378**
Connections (OO)	4,034	4,087	4,051	4,449	6,298	**4,584**	5,100	4,700	4,300	**4,700**

Source: PNGL and the Utility Regulator

4.22 From the tables above the following may be observed:

- Table 8 highlights how PNGL has performed in line with PC03 determined allowances, retrospectively adjusted for actual outputs. Results show that in the period 2007-11, PNGL achieved its budgeted forecast for capex and slightly over-performed (i.e. underspent) on opex.
- PNGL is seeking higher allowances in GD14 to deliver fewer outputs than delivered during 2007-2011 (Table 9).
- Requested annual allowances sought in GD14 are higher than in PC03 (£30.4m vs. £27.0m). On average, PNGL is seeking £3.4 million more allowance per year of GD14 than it spent in PC03, which is a real increase of 13%.
- PNGL's capex allowance request for GD14 (£13.6m) is broadly equivalent to its actual capex spend in 2007 to 2011 (£13.3m) albeit for fewer outputs, while the opex allowance request for GD14 is significantly higher (23%) than actual opex in PC03 (£16.8m vs. £13.7m annually).
- PNGL on average expects domestic connections to be higher than in PC03. This reflects a major refocus in PNGL's connection strategy towards domestic customers, and especially owner occupied and social housing rather than new

build (given the deterioration in the housing market). Nevertheless, the projected connections are lower than those achieved in 2012 (10,378) and slightly below those expected in 2013 (9,288).

4.23 It is worth noting that PNGL did provide some detail and supporting commentary to explain why costs are forecast to increase. More detail and discussion is provided in the sections to follow.

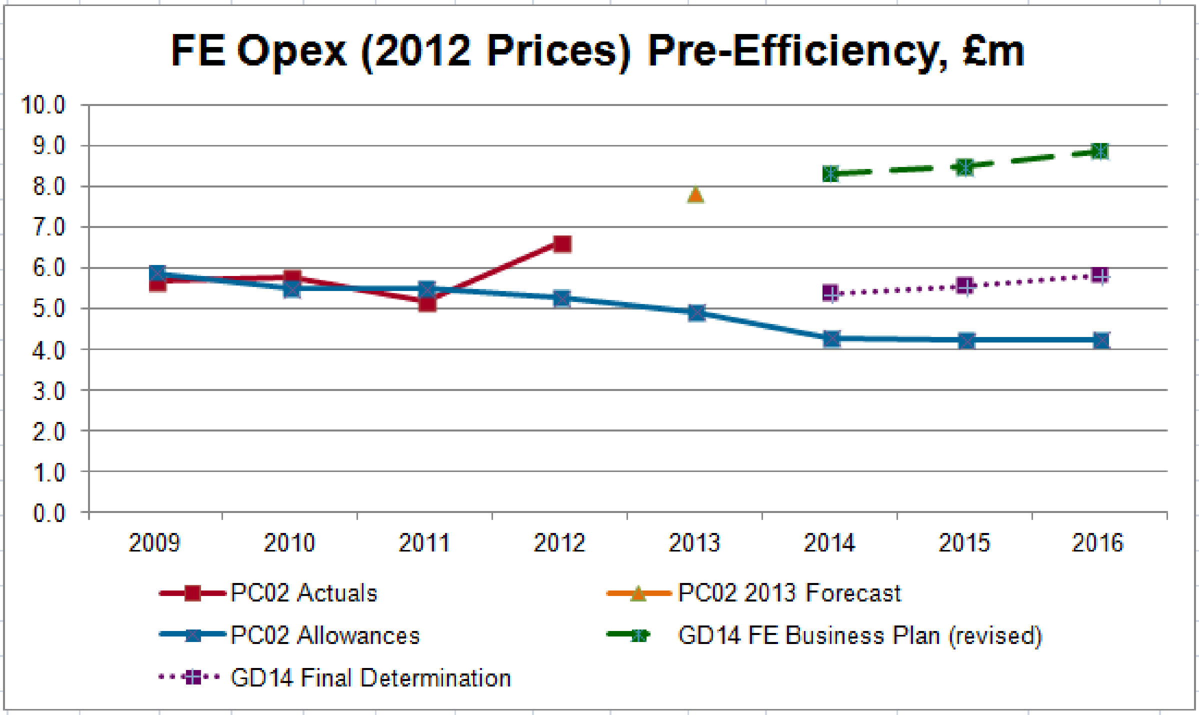
Firmus Energy

Overview

4.24 Figure 7 below shows a summary of FE's opex costs from 2009 to 2012, the forecast outturn for 2013, its requested allowances for GD14 and our final pre-efficiency allowance[18].

4.25 Figure 8 shows the same information for FE's capex.

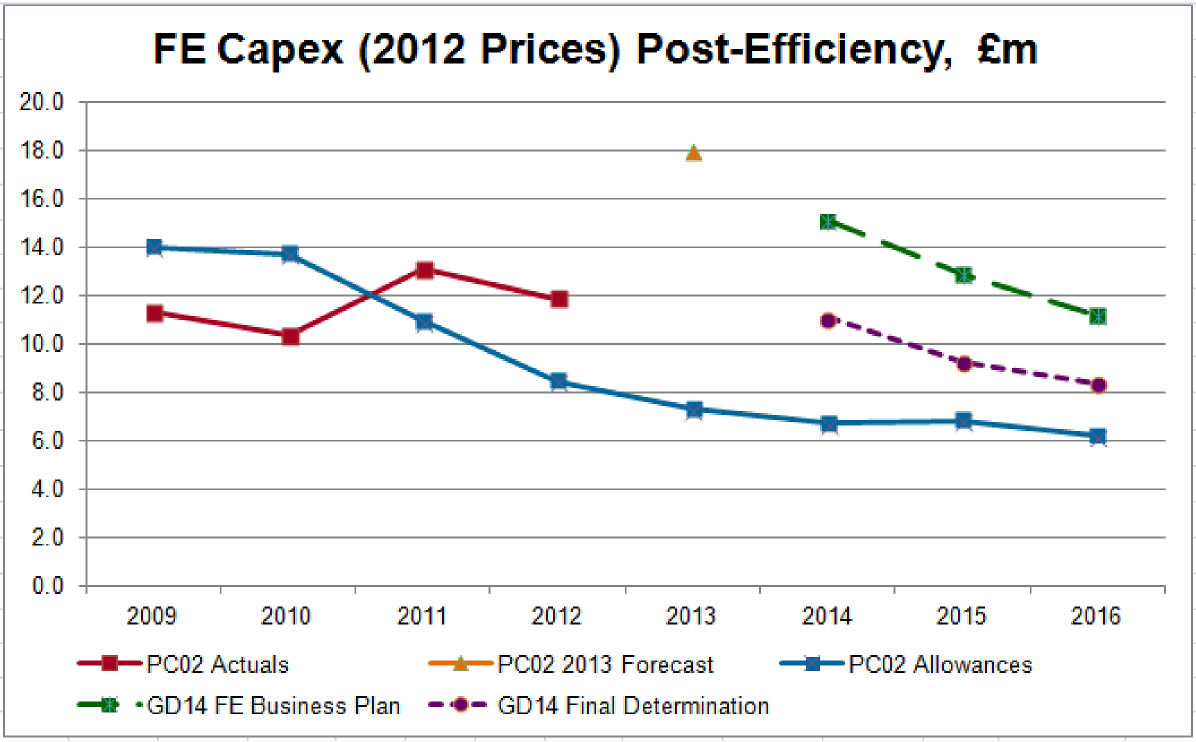
Figure 7 – FE operating expenditure (pre-efficiency), £m



Source: FE and the Utility Regulator

[18] Note that FE's historical actual costs include costs which should be removed and allocated to the FE supply businesses (this is discussed in more detail in section 4 of this paper). The historical actual costs are therefore not comparable on a like-for-like basis with their revised submission for 2014-2016 shown in the graph and with our final determination.

Figure 8 – FE capital expenditure (pre-efficiency), £m



Source: FE and the Utility Regulator

4.26 Overall, FE's requested allowances are significantly higher than historical costs. This is particularly the case for opex. Capex is also significantly higher, especially in the early years and then it gradually falls to historical levels by the end of the GD14 period.

Operating Expenditure

4.27 The table below summarises the opex allowances requested by FE in their original submission. FE provided more detail of the build-up of some of the individual cost lines in its original submission and after we issued our information requests.

Table 10 – FE operating expenditure original submission, £k

Cost item	2014	2015	2016	Total
Advertising, marketing and PR	1,555	1,505	1,405	**4,465**
Bank charges	9	9	9	**27**
Fees and consulting	223	123	123	**469**
Insurance	232	270	305	**806**
Licence fees	280	280	280	**840**
Manpower	2,091	2,210	2,430	**6,730**
Network maintenance	1,214	1,326	1,522	**4,063**
Office costs (incl. IT)	456	459	459	**1,374**
Parental recharges	1,210	1,132	1,155	**3,498**
Professional subscriptions	12	12	12	**36**
Rates	918	1,039	1,065	**3,022**
Training	88	90	119	**297**
Travel and transport	229	239	242	**711**
Total	**8,517**	**8,695**	**9,126**	**26,338**

Source: FE

4.28 The following table shows the FE 'revised' opex submission. The main revisions in this table can be summarised as follows:

- Costs which should be apportioned to the FE supply businesses have been removed from the submission;
- FE submitted a request for increased insurance costs as part of their response to the draft determination and also submitted a new request for network maintenance costs relating to meter exchanges from prepay to credit meters;
- Costs have been removed from the parental recharges cost line and allocated to emergency and maintenance costs as advised by FE

4.29 It is important to note that requested costs in some cost lines also include costs which should have been apportioned to the supply company. We consider the determined allowances granted are appropriate for the distribution business.

Table 11 – FE operating expenditure 'revised' submission, £k

Cost item		2014	2015	2016	Total
Advertising, marketing and PR		**1,555**	**1,505**	**1,405**	**4,465**
Bank charges		**9**	**9**	**9**	**27**
Fees and consulting		**223**	**123**	**123**	**469**
Insurance	Original Request	232	270	305	
	Additional Request	29	20	9	
	Supply Allocations	-33	-34	-34	
	Revised Request	**227**	**255**	**280**	**762**
Licence fees		**280**	**280**	**280**	**840**
Manpower	Original Request	2,091	2,210	2,430	
	Supply Allocations	-130	-124	-152	
	Revised Request	**1,961**	**2,086**	**2,278**	**6,325**
Network maintenance	Original Request	1,214	1,326	1,522	
	Moved from Parental Recharges	200	201	203	
	Additional Request	26	30	34	
	Supply Allocations	-79	-92	-104	
	Revised Request	**1,361**	**1,465**	**1,655**	**4,483**
Office costs (incl. IT)		**456**	**459**	**459**	**1,374**
Parental recharges	Original Request	1,210	1,132	1,155	
	Moved to Parental Recharges	-200	-201	-203	
	Revised Request	**1,010**	**931**	**952**	**2,894**
Professional subscriptions		**12**	**12**	**12**	**36**
Rates	Original Request	918	1,039	1,065	
	Supply Allocations	-9	-9	-10	
	Revised Request	**909**	**1,030**	**1,055**	**2,993**
Training		**88**	**90**	**119**	**297**
Travel and transport		**229**	**239**	**242**	**711**
Total		**8,320**	**8,484**	**8,869**	**25,676**

Source: FE and Utility Regulator

4.30 Throughout the remainder of the final determination, we use the 'revised' submission when we state FE's requested.

4.31 FE's opex requests and allowances are reviewed in detail in section 6 of this consultation paper. At this point we note that the aggregate opex request for FE has increased significantly compared to prior years. The average annual opex requested is 30% higher than our determined allowances for the most recent price control (PCR02, covering 2009-2013) and 58% higher than FE's actual costs for the 2009-2011 period. The main drivers for this increase appear to be office costs, maintenance and manpower.

Capital Expenditure

4.32 The table below sets out a summary of the overall capex allowance requested by FE. More detail on some of the individual cost lines was also submitted by FE, which is examined and discussed in section 8.

Table 12 – FE capital expenditure submission, £k

Cost item	2014	2015	2016	Total
4 bar mains	3,905	2,641	2,519	**9,064**
Governors	200	133	132	**465**
Infill Mains	3,454	3,219	2,620	**9,292**
Low pressure	819	566	498	**1,882**
Domestic services	3,558	3,609	3,396	**10,564**
Domestic meters	793	805	755	**2,354**
I&C services	625	422	209	**1,256**
I&C meters	198	134	66	**397**
Large Loads Services	17	17	17	**52**
Large Loads Meters	17	17	17	**52**
Telemetry	38	37	24	**99**
Other Capex	300	300	50	**650**
Traffic Management Act	1,147	958	854	**2,959**
Total	**15,072**	**12,858**	**11,158**	**39,087**

Source: FE

4.33 FE's requested capex allowance is 23% higher (in real terms) than average actual capital expenditure during the previous price control, PCR02. This is both because the workload is projected to increase and also because FE has suggested that unit rates will increase.

FE Connection Assumptions

4.34 FE's assumed level of connections over the control period is set out below.

Table 13 – FE determined new connections (average per year)

Customer category	Annual connections
I&C medium	2
I&C small	100
New build	800
NIHE	1,133
Existing / 'warm' homes	2,000
Total	**4,035**

Source: FE

GD14 Projected Outputs versus FE PCR02 Outputs

4.35 As part of its submission, FE also provided information on the level of outputs it plans to deliver over the control period, the main ones being:

- Kilometres of mains laid; and
- Connections.

4.36 For illustrative purposes, we set out below:

- FE's historical performance comparing actual audited accounts for 2009 to 2011 (the latter being the most recent year for which we had detailed audited data at the time of writing) against the PCR02 determination (with and without retrospective adjustments); and
- FE's actual performance in calendar years 2009 to 2011 and compare this with its allowance requests and forecast outputs for 2014 to 2016.

Table 14 – PCR02 actuals versus PCR02 determination (with and without retrospective adjustments), £k

Cost items and outputs	2009	2010	2011	Average	2009	2010	2011	Average	2009	2010	Average	Average
	Actuals 2009-11				PCR02 Determination				PCR02 retrospectively adjusted			
Capex, £m	10.4	9.5	12.1	**10.6**	13.9	13.7	10.9	**12.8**	12.3	11.9	14.5	**12.9**
Opex, £m	5.7	5.8	5.2	**5.6**	5.9	5.5	5.5	**5.6**	5.6	5.2	5	**5.3**
Pipe laid, km	79	90	110	**93**	100	94	76	**90**	79	90	110	**93**
Connections-Total	2,080	2,449	3,506	**2,678**	2,115	2,087	2,082	**2,095**	2,080	2,449	3,506	**2,678**
Connections (OO)	400	523	1,034	**652**	400	400	400	**400**	400	523	1,034	**652**

Source: FE and the Utility Regulator

Table 15 – PCR02 actuals versus FE GD14 Submission, £k

Allowances and Outputs	2009	2010	2011	Average	2014	2015	2016	Average GD14 submission
	Actuals			2009-11	FE Submission			
Capex, £m	10.4	9.5	12.1	**10.7**	15.1	12.9	11.2	**13.1**
Opex, £m	5.7	5.8	5.2	**5.6**	8.3	8.5	8.9	**8.6**
Total cost, £m	**16.1**	**15.3**	**17.3**	**16.3**	**23.4**	**21.4**	**20.1**	**21.6**
Pipe laid, km	79	90	110	**93**	87	71	63	**74**
Connections - total	2,080	2,449	3,506	**2,678**	4,152	4,102	3,852	**4,035**
Connections - OO	400	523	1,034	**652**	2,000	2,000	2,000	**2,000**

Source: FE and the Utility Regulator

4.37 From the tables above, we make the following observations:

- Table 14 shows that FE has outperformed its retrospective forecasted targets in capex and opex for PCR02, achieving greater connections, meeting its outputs using less money than forecasted at the PCR02 determination. Key efficiencies were achieved in manpower, fees and consultancy, mains, domestic meters and additional capital within capex.

- Overall allowances sought by FE for GD14 are significantly higher than PCR02 actuals (see Table 15).
- FE is seeking on average £2.4 million more capex allowances in each year of GD14 than it has spent per year in PCR02. This is a real increase of 23%.
- FE has requested £3.2 million more opex in each year of GD14 than it has spent per year in PCR02. This represents a real increase of about 57%.
- However, FE forecasts a significant increase in connections – 51% in comparison to the PCR02 actual average. This is driven mostly by an increase in domestic connections and particularly for OO and NIHE, rather than new build housing given the deterioration in economic activity.

5 Operating Expenditure, PNGL

Update from Draft Determination

5.1 For connections we have updated the allowance to consider more relevant information, which resulted in the connection incentive allowance increasing from £480 to £540 per additional connection.

5.2 For emergency the main changes are to defer the target reductions to emergency call numbers and the efficiency savings relating to the call centre contract until 2015. This results in increased allowances for PNGL over the three years.

5.3 For maintenance activities, we have taken account of new information provided by PNGL which has resulted in an increased level for the base maintenance costs and additional allowances have been granted in relation to meter battery replacement. We have also removed the 10% efficiency target that was applied to maintenance costs in the draft determination.

5.4 There are no changes for insurance, licence fees, office costs, IT or professional & legal fees.

5.5 For network rates, we have updated the calculation to use the determined revenues from this price control, rather than the revenues submitted by PNGL.

5.6 Our approach to the manpower determination has not changed substantially, however in updating the analysis we identified a formula error within the model which we have now updated. We have also updated the manpower costs to be recovered through the connection incentive mechanism for the final determination.

5.7 The only change for smaller items is for fleet costs, where PNGL outlined a submission error that we reflected in our final allowance.

Introduction

5.8 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

5.9 PNGL categorises its operating expenditure into 19 different cost lines as follows:

Advertising, marketing and PR	**Human resources**	**Manpower**	**Rates**
Billing	**Incentives (for customers)**	**Network maintenance**	**Stationery**
Emergency costs	**Information Technology**	**Office costs**	**Telephone and postage**
Entertainment	**Insurance**	**Own use gas**	**Travel and subsistence**
Fleet costs	**Licence fees**	**Professional and legal fees**	

5.10 In assessing the reasonableness of the expenditure claimed by PNGL for these cost lines, we have first grouped them into broader categories and then applied what we consider to be an appropriate approach to each.

5.11 Our grouping takes into account the importance of the cost items in PNGL's cost structure, with greater scrutiny exercised over those that represent the greater cost. We also consider the extent to which some cost items must be separately examined because of the particular way they are treated (e.g. pass-through), or due to other specific circumstances calling for individual treatment, irrespective of their magnitude.

5.12 More specifically, we first identify the items that collectively constitute the largest proportion of total operating expenditure and which separately represent a material share of overall claimed costs (typically, more than about 5%). We examine these in some detail on an individual basis, using evidence furnished by PNGL in its original submission and in responses to our subsequent information requests. The relevant cost lines are:

- Advertising, marketing and PR (including customer incentives);
- Emergency costs;
- Insurance;
- Manpower;
- Network maintenance; and
- Rates.

Together, these items represent 80% of PNGL's claimed allowances.

5.13 Next, we examine cost items that by their nature require individual assessment, although they might not represent a significant component of overall expenditure. This could be because they are pass-through items (as is the case with licence fees), or if there are other specific circumstances applying, such as for:

- Office costs and IT, where the requested allowances are significantly higher than historical actual costs and/or determined allowances; and
- Professional and legal fees, in light of the 'abnormal' costs incurred in 2012 in the context of the Competition Commission (CC) inquiry and the significant increase in PNGL's claimed allowances for this category.

5.14 We have considered the remaining (smaller) cost lines collectively, following the precedent set in PNGL12.

5.15 We first set out the connection assumptions we have used in our modelling. This is necessary since some opex and capex allowances will vary explicitly with the number of connections, both in the setting of *ex ante* allowances and later in the retrospective adjustments that are made *ex post* once actual connections are known. (The way we will make retrospective adjustments is discussed later in Section 15).

Our Connection Assumptions

5.16 PNGL submitted a Market Development Paper as part of its business plan submission for GD14 outlining that difficult economic conditions have impacted connection numbers in the past and their sustainability going forward. It also indicated that fewer owner occupier properties are likely to switch to gas as the number of new build rises. On this basis, PNGL proposed that owner occupier connections would drop from the current level to average 4,700 during GD14.

5.17 We have considered the PNGL arguments but do not believe they justify reducing the target from current levels. The connections incentive was introduced in 2012 to ensure PNGL had a strong incentive to encourage owner occupiers to switch to gas and provided a high level of flexibility for PNGL to target the incentive however it considered appropriate – e.g. advertising, discounts, etc. This mechanism has been very successful and has seen large increases in connections allowing PNGL to earn c£2m in outperformance in 2012-2013.

5.18 The success of the mechanism allows us to reset the connections target at the current level. Therefore we have set the target for owner occupied connections in the formation of the connections incentive mechanism (discussed further below) as 6,500 per annum against an average of 4,700 as submitted by PNGL. The most recent performance of PNGL in OO connections is seen as a fair indicator as to the level of connections achievable for this price control period.

5.19 The targets in respect of NIHE and I&C connections were accepted as submitted. Our determined connection targets are set out in the table below.

Table 16 – Determined cumulative connections for PNGL for the GD14 period

Connection type	PNGL submission	Final Determination
Domestic – OO	14,100	19,500
Domestic –NB	7,600	7,600
Domestic – NIHE	3,000	3,000
I&C	1,134	1,134
Total	**25,834**	**31,234**

Source: PNGL and the Utility Regulator

Connections Incentive

The connections incentive mechanism

5.20 In PNGL12, we moved away from setting fixed allowances for sales-related costs and toward remunerating PNGL on the basis of outputs, that is, connections – this was referred to as a 'A+M+PR' incentive . Moreover, in setting a per connection allowance, we sought to emphasise the need for all future connections made by PNGL to its network to be economic.

5.21 Accordingly, we developed the 'A+M+PR' mechanism in a way that sought, on average, to ensure that making a new connection to the network would deliver positive net present value (NPV) revenues over a suitable time period. That is, the per-connection allowance was calculated so that the present value of direct revenues from a connection was equal to or exceeded the present value of direct costs of making that connection. The allowance was payable only for Owner Occupier (OO) housing connections and for those above 25% of the targeted number of connections, on the assumption that some customers would switch to gas in any case without any direct marketing or selling.

5.22 Allowances of this type to incentivise consumers to connect were not envisaged at the start of PNGL's operations in 1996, but we determined that this was needed to increase connections in the early years. Indeed, originally PNGL had intended to complete all connections by 2016. A significant reason for allowing such cost allowances was to enhance the branding of gas so that it was seen as the fuel of choice in Greater Belfast. Given the high ongoing levels of connections, it appears this goal has largely been achieved.

5.23 In the PNGL12 determination we considered that it was appropriate to continue to grant PNGL allowances but at the same time, we moved to an output-based mechanism where the allowance would be obtained only for connections actually achieved. Hence, the per connection allowance of the A+M+PR mechanism was employed to substitute for (a sub-set of) PNGL's sales-related costs, namely, advertising, marketing and PR, incentives (i.e. monies offered to customers to connect to gas), relevant staffing costs and associated corporate overheads that can be apportioned to sales activities.

Review of the mechanism

5.24 In our previous price control determination, we also stated that the connections incentive and its components would be reviewed to assess whether it has worked as anticipated and whether it is reasonable to retain going forward. In undertaking this assessment, we have tried to answer the following two questions:

- Is it necessary to retain a connections incentive mechanism and, if so,
- Is the present mechanism 'fit for purpose' or does it require some change?

5.25 In answer to the first question, we estimate using PNGL figures that OO connections in 2012 and 2013 will be 47% higher (on an average annual basis) than the connection assumptions we adopted in the PNGL12 price determination and 32% more than actual average annual connections during the PC03 period (2007-2011). Although this performance may not be solely attributed to the A+M+PR mechanism, we believe it has been an important contributing factor.

5.26 Notwithstanding the above, even without this output-based mechanism, a significant number of residential customers would connect to gas (regardless of any marketing and sales effort from PNGL). The intention of the incentive allowances was never meant to be long term. We had indicated in PNGL12 that with the market maturing and as we moved beyond 2016 there would be a case for reducing the allowance by 50% from 2017. This still remains the intention as we think it important to phase the allowance out over time and move to a more standard approach consistent with a mature network. We plan to conduct a general review of connections policy as part of GD17 and will consider the level of incentive required to maintain connection activity.

5.27 For GD14, we plan to continue with a mechanism which excludes 25% of the targeted connections from the calculation of the allowances on the basis that they are 'non-additional'. Importantly, the allowance also only applies to OO domestics where the incentive to switch may not be as strong as for I&C customers.

5.28 Turning to the second question, we feel that it is necessary to review the quantum of the allowance. We have reviewed the basis of the calculation in PNGL12 and also taken into account the actual performance of PNGL since the incentive was introduced. We also note that there are a range of other resources and schemes available which provide funds towards natural gas conversion and can complement the connection incentive for eligible customers, e.g. Warm Homes Plus scheme[19] and Boiler Replacement Programme[20] funded by the Department for Social Development and a range of schemes funded through NISEP[21] (Northern Ireland Sustainable Energy Programme). The Warm Homes Plus scheme provides up to £6500 towards installation of a fully controlled energy-efficient oil or gas central heating system where no system currently exists or towards conversion of an existing LPG, solid fuel or Economy heating system to oil or natural gas. The Boiler Replacement Programme provides, depending on income, £400 or £700 towards the replacement of an old inefficient boiler with a more energy efficient one (£500 or £1000 if controls

[19] See http://warm-homes.com/ for further details.
[20] See http://www.nihe.gov.uk/index/benefits/boiler_replacement_allowance.htm for further details.
[21] See http://www.uregni.gov.uk/uploads/publications/130501_NISEP_List_of_Schemes_2013-14_2.pdf for further details.

are also installed). The funds available through the NISEP schemes vary depending on scheme and can, in certain cases, provide for installation of a fully funded natural gas heating system with controls.

5.29 In taking into account direct capex costs associated with a new connection, the PNGL12 calculation assumed that these only entail service and meter costs. However, in addition to these costs, we believe that it is appropriate to include infill costs that should be attributed to new connections. Accordingly, our calculations below for determining the per connection allowance for GD14 also take into consideration infill costs. While much infill has already been constructed, it has mainly been to ensure domestic properties have been passed and it is appropriate that such costs should be taken into account in this calculation. This still means that the opex costs associated with each new customer and the larger mains costs forming the network backbone are not included in the calculations.

5.30 Separately, we also reviewed the actual costs per connection that will be incurred by PNGL during the 2012-2013 control period. We estimate that PNGL's actual costs during PNGL12 will be £443 per connection (£2012) on the basis of 12,425 connections in total. This equates to a per connection allowance of £533 (£2012) when adjusted to account for and exclude the 'non additional' connections (which were fixed at 1,050 connections per year in PNGL12).

Mechanism principles

5.31 The main principles used in the development of the mechanism remain largely unchanged from PNGL12, subject to the modifications discussed above. The key elements are as follows:

- The opex allowance per connection has been calculated using the formula:

Allowance per connection = (Revenue per connection) – (Direct capex cost per connection)

Where:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

AND

Direct capex cost per connection = Determined infill cost per OO connection + Determined meter cost + Determined service cost

- We have developed a model around the above formulae using estimates, where necessary, for some key assumptions within the formulae.
- The mechanism will apply, as before, only to domestic OO housing. We have therefore separately granted a certain level of fixed allowances for sales-related costs that are NOT associated with OO connections.

Revenue per connection

5.32 A reminder of the formula:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

5.33 The assumptions we have used are as follows:

Variable	Assumption
Average consumption (A)	**410 therms per annum (tpa)** This is the approximate average consumption figure for both gas distribution licensees[22]
Conveyance tariff (B)	**40 pence per therm (ppt)** This is an estimate of the approximate tariff applicable to domestic customers
Recovery period (C)	**15 years** This is considered a suitable payback period for the recovery of direct connection costs. Thereafter, all future revenues would contribute to the costs of the wider network
Average revenue per annum per OO connection	**£164** Calculated as: (A) x (B)
Net present value (NPV) of average revenue over recovery period	**£1,729** NPV of: (A) x (B) discounted over the years in (C)

Direct capex cost per connection

5.34 A reminder of the formula:

Direct capex cost per connection = Determined infill cost per OO connection + Determined service cost + Determined meter cost

5.35 We look at capex allowances in detail in section 7, but to summarise:

Variable	OO customers
Infill cost	£310
Service cost	£666
Meter cost	£217

Allowance per connection

5.36 Using the above figures we have determined an allowance per connection:

Allowance (£) = (Revenue per connection) – (Direct capex cost per connection)

= 1,729 – (310 + 666 + 217)

= 536 (which we will round up to £540)

5.37 The figure of £540 is in line our calculation of PNGL's expected actual per connection costs for 2012-13 (£533). This allows for the economic principles to be applied in setting the incentive and we therefore have set the final allowance at £540 for all additional OO connections.

Allowance application

5.38 We have calculated an appropriate allowance of £540 per connection to cover those opex costs we believe can be directly apportioned to sales-related activities for

[22] We have sought to develop a common per connection allowance for both PNGL and FE and therefore adopt similar assumptions for both companies.

domestic OO properties. However, the full allowance is not applicable to *all* new OO connections.

5.39 As already discussed and consistent with our PNGL12 determination, we consider that there will be a certain number of OO connections that would occur anyway without any direct marketing or selling to these customers. We describe these connections as "non-additional". Since PNGL could in theory avoid any sales-related costs to connect such customers, no allowance will be applicable for these customers. We have assumed (as for PNGL12) that 25% of all new connections will fall into this category.

5.40 The total number of forecast OO connections is 6,500 per annum as set out in Table 16. This makes the non-additional connections 1,625[23].

5.41 All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We plan to review the mechanisms in place to ensure this is the case in the coming months. We expect the GDNs to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas. We will further discuss with GDNs how this should be defined.

What costs are being replaced by the mechanism?

5.42 The relevant opex costs are:

- Advertising, marketing and PR;
- Incentives;
- OO Sales related staff, including relevant director; and
- Shared corporate overheads.

5.43 The full allowances requested against the distribution business for these cost items are as follows:

Table 17 – Potential PNGL costs to be replaced by Connections Incentive Mechanism, £k

Cost item	2014	2015	2016
Advertising, Marketing and PR			
Market development	860	829	789
TOTAL	**860**	**829**	**789**
Incentives			
Domestic	746	687	629
I&C	37	37	37
TOTAL	**783**	**724**	**666**
OO Sales Related Staff (inc. Director)	**1,444**	**1,424**	**1,386**
Corporate overheads (apportioned)	**593**	**597**	**596**
Total	**3,680**	**3,574**	**3,437**

Source: PNGL and the Utility Regulator

5.44 The *Corporate Overheads (apportioned)* cost line above refers to a share of overhead costs we consider appropriate to apportion to the Business Development Department. The costs are:

- Fleet costs;

[23] For the avoidance of doubt, the non-additional target is fixed at 1,625 connections, irrespective of actual output connections.

- Human Resources;
- Insurance (buildings and car insurance);
- IT;
- Office Costs;
- Rates (excluding network rates);
- Stationery;
- Telephone and postage;
- Travel and subsistence; and
- Corporate support personnel AND their apportioned share of the above costs (by this we are referring to staff in the Finance department including the Finance Director and the Regulatory Affairs section of the Commercial Department, and to the Chief Executive Officer).

Our intention is that these costs are to be recovered via the mechanism. Therefore we have reduced the fixed allowances for these costs items by an appropriate amount. (This explains why for example our "smaller items" determination as set out in Table 31 is slightly higher than what is presented in the final overall opex allowance summarised in Table 32 at the end of this section.)

5.45 We consider that the costs set out in the above table should be recovered through the mechanism but we acknowledge that some element of these costs may not be directly linked to domestic OO sales. We have therefore determined a fixed sum against some or all of the above cost lines, in addition to the allowance recoverable via the mechanism.

5.46 The fixed sums we have determined, along with our rationale, are set out in the table below. Note that total costs in our determined fixed allowances have been rounded to the nearest £k.

Table 18 – PNGL fixed allowances, £k

Cost Item	2014	2015	2016	Rationale
Advertising, Marketing and PR				
Market development	30	30	30	We accept that some of these costs will relate to connections other than domestic OOs, so have pro-rated the total cost based on forecast I&C connections.
Corporate affairs	130	130	130	We have allowed a fixed corporate affairs cost in line with that applied within PNGL12
TOTAL	**160**	**160**	**160**	
Incentives				
Domestic	-	-	-	Incentives offered to domestics are to be fully recovered via the mechanism.
I&C	-	-	-	Consistent with our PNGL12 determination, we will no longer grant an explicit allowance for I&C incentives.
TOTAL	**-**	**-**	**-**	
Business development department (incl. Sales Director)	**730**	**730**	**730**	A detailed review of the Business Development Department indicates that there are some members of this team whose activities are not focused on OO domestics. We further accept that the Director of Business Development will spend some time on activities not related to OO domestics.
Corporate overheads (apportioned)	**-**	**-**	**-**	Corporate overheads have already been apportioned using a ratio of those staff in the Business Development Department (whose focus is on OO domestics) to the total staffing complement at PNGL. Therefore no fixed sum has been determined.
Total	**890**	**890**	**890**	

Note that total costs have been rounded down to the nearest £k.

Source: The Utility Regulator

5.47 Another modification we have implemented is the introduction of a risk-reward mechanism to provide stronger incentives to PNGL to outperform its connection targets. This is in response to the CC's price determination, which recommended that changes to the connections incentive be explored for strengthening the PNGL volume incentive (see paragraphs 10.48 to 10.50 of the CC decision).

5.48 The CC asked us to examine whether the connections incentive in PNGL12 was providing an incentive of the same magnitude as the previous volume incentive before the price cap regime was removed. The magnitude of the price cap regime is highlighted by the loss PNGL made under this in 2006, which amounted to almost £10m. For comparison, if we take the most extreme example and assume PNGL connected no customers under the PNGL12 connections incentive regime we calculate that it could lose up to £3m. This analysis would support the position that the PNGL12 regime did not provide an incentive regime of similar magnitude to the volumes incentive.

5.49 Given this analysis, we have set out below how the magnitude of the incentive could be increased.

5.50 Under the existing A+M+PR mechanism, PNGL receives the stipulated per connection allowance for all 'additional' connections (i.e. those above the 25% threshold) irrespective of whether it under- or outperforms the connection targets. In order to reinforce PNGL's incentive to connect customers, we will reward if PNGL exceeds the target connections that would increase the per connection allowance for additional connections exceeding the target number of connections by the same proportion that the connections target is overachieved. Conversely, a penalty will apply if PNGL falls short of the target connections that would reduce the per connection allowance for all additional connections by the same proportion that the connections target is underachieved. This under- or outperformance would be capped at +/- 50%[24].

5.51 To demonstrate how the new incentive mechanism might work, consider the following examples:

- *Outperformance* – the connection allowance is £540 and the target (excluding non-additional) connections is 4,875, but PNGL outperforms by connecting 5,363 OO customers (excluding non-additional). As the connections outperformance is 10% (= 5,363 / 4,875 – 1), a unit connection allowance of £594 (= £540 x (1+10%)) will be payable for the 488 extra connections gained; the standard allowance of £540 would still apply to the original 4,875 connections. Total allowances would therefore equal £2,922,372 (i.e. (£540 x 4,875) + (£594 x 488)).
  Underperformance – the connection allowance is £540 and the target (excluding non-additional) connections is again 4,875, but PNGL this time underperforms by connecting 4,387 OO customers (excluding non-additional). As the connections underperformance is 10% (= 4,387 / 4,875 – 1), the unit connection allowance payable will be £486 (= £540 x (1-10%)) for all connections (excluding non-additional). Total allowances in this case would equal £2,132,082 (i.e. £486 x 4,387).

Summary

5.52 The connections incentive mechanism is summarised as follows:

- The full allowance is £540 per OO connection, applicable to all new OO connections after consideration of non-additional connections.
- The total aggregate allowance has been calculated by multiplying this allowance by the forecast number of OO connections (excluding non-additionals), less a sum for recharges to Phoenix Energy Services (PES) of £50k per annum.
- The aggregate allowance will be retrospectively adjusted at the time of the next price control using the actual number of connections.
- The allowance per connection could also be retrospectively adjusted according to whether PNGL achieves the targeted number of OO connections. The proportional increase (reduction) in the allowance would be equal to the percentage of over (under) achievement of the connection target, subject to the +/- 50% cap and collar.
- The allowances to be recovered via the mechanism will replace those costs set out in Table 17. Where an element of fixed allowance is considered appropriate, this has been included in our overall allowances.
- We expect to reduce the full per connection allowance by 50% from 2017 onwards. We will consult on connections costs and incentives further as part of GD17.

[24] For the avoidance of doubt, the minimum allowance that will be achieved equates to £270 per additional connection and the maximum that can be achieved equates to £810 per additional connection.

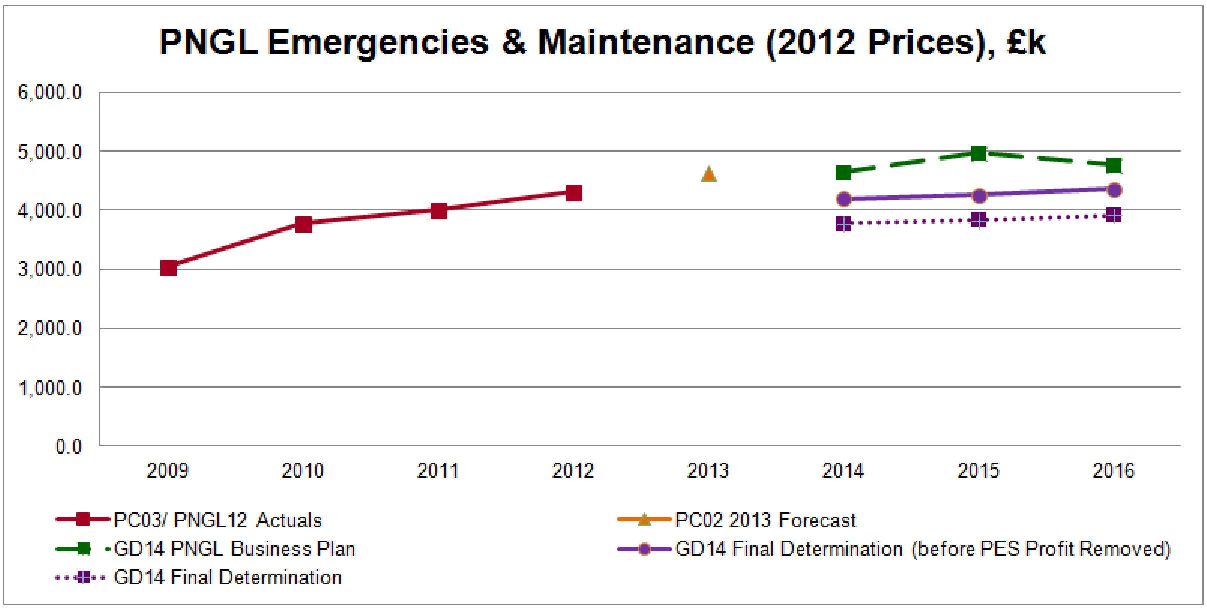
Emergency and Network Maintenance Costs

Overview

5.53 PNGL has requested allowances of £4.6 million, £5.0 million and £4.8 million in 2014, 2015 and 2016 respectively to cover emergency and maintenance costs. For comparison, historical actual costs for 2010-2011 averaged around £3.9 million.

5.54 The following graph compares the historical actuals against the GD14 submission and shows the allowances for GD14. It is important to note that the historic actual costs include the profit element from Phoenix Energy Services (PES) related works which is disallowed in the final determination.

Figure 9 – PNGL emergency and network maintenance historical costs and GD14 Submission, £m



Source: PNGL and the Utility Regulator

5.55 The graph shows that PNGL has forecast increasing emergency & network maintenance costs year on year for 2014-2016, where the allowances in the final determination indicate a reduction for 2014 and then a slightly increasing trend. The key factors influencing the determined emergency and maintenance allowances are:

- From 2015, PNGL is being targeted to reduce the number of calls received by its emergency call centre, as the number of inappropriate/general inquiry calls received historically has been around 50% of the total calls, which is particularly high compared with counterparts in GB.
- We have requested that PNGL and FE work more closely together in procuring an emergency call centre contract in order that savings be made.
- We have retained the approach used in the last two price controls where we remove the profit element from Phoenix Energy Services (PES) related works. However, in GD14 we have not only deducted the profit element from the emergency first calls; we have also removed the profit element from the specific maintenance activities where PNGL has informed us that the activities are completed by the PES First Call Operatives.

- There is a change of policy for domestic meter exchanges where PNGL will no longer be granted an allowance to cover the cost of all domestic meter exchanges. In some cases, customers would be required to pay the cost of the meter exchanges up front. However, it is important to note that PNGL will recover these costs directly from suppliers and therefore this is not a reduction in PNGL revenues.

5.56 The analysis of emergency and maintenance costs are explained in more detail throughout this section, and supplementary information has also been provided in Appendices 1 and 2.

5.57 We commissioned our engineering consultants, Rune Associates Limited (Rune), to advise on the appropriateness of PNGL's allowance request for emergency and network maintenance costs.

5.58 PNGL has previously reported its costs and forecasts in terms of the account headings used within its business. To undertake the review for the GD14 price control for both PNGL and FE, we asked Rune to develop a reporting template that would attempt to get both companies to move to a common reporting format and would provide an element of comparability to GB networks.

5.59 We have analysed and reported the emergency and maintenance costs under the following headings:

- Call centre costs
- Emergencies (First Call Costs)
- Repair activities
- Maintenance activities.

5.60 Rune has attempted to allocate the costs and forecasts from the PNGL submission into these four headings, and has been assisted in this objective by PNGL through additional information submitted in the new template.

5.61 The following sections consider each of these headings in turn and a summary table is provided at the end of this section showing the summary submission and allowance for each area.

5.62 Illustrative unit rates for comparison purposes in tables are shown in italics to the nearest £.

Call Centre Costs

5.63 Call Centre calls comprise emergency reports that require investigation by a first call operative (FCO) and calls which can be generally categorised as general enquiries and no further action is required. PNGL has requested an allowance of £0.6m per year in 2014, 2015 and 2016 for this purpose.

5.64 The principal driver for the call centre activity has been identified as the total number of customers connected to the network. PNGL forecasts an on-going flat rate for the number of calls per 10,000 customers, whereas we believe that the trend should indicate a reduction. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that may initially generate a higher emergency call rate.

5.65 Rune developed a model to determine appropriate call centre costs for 2014 – 2016. Further details of the model, including the principles and assumptions behind the model have been provided in Appendices 1 and 2.

5.66 The model targets PNGL to reduce the number of calls received from existing customers by 3% per year and by 1% per year from new customers, starting in 2015.

5.67 The model generated forecasts for the number of calls received (based on number of calls per 10,000 consumers). PNGL's calls per 10,000 consumers are at a higher level than call volumes that would typically be seen by GB GDNs, despite allowing for additional calls in NI as a result of the large number of prepaid meter problems. In 2010 and 2011, around 50% of the total calls received by the emergency call centre were general enquiry calls. This is an extremely high level of inappropriate calls, and PNGL would be expected to manage these levels downwards. We therefore consider the target reductions in total call numbers are set at an achievable level.

5.68 An increasing call rate trend has been assumed for the total number of calls, albeit at a lower level than the PNGL forecast submission. This incorporates the efficiency improvements of between 1% and 3% as outlined above.

5.69 Rune has also formed the opinion that whilst PNGL and FE use the same provider for the call centre, each places its own contract for the provision of emergency call handling and dispatch. Rune believes that savings could be made in the cost of procuring this service by PNGL and FE working more closely together. In the event that further licences are granted within NI, it should be possible to extend such savings to any new licence holder.

5.70 In the draft determination we proposed a 50% saving of the fixed modelled call centre costs starting in 2014 (resulting in a reduction of £127,500 for PNGL over the three years of the control). Following PNGL's and FE's responses to the consultation we continue to believe savings are appropriate; however, after further consideration, we have concluded that time is required for the companies to consider the options for achieving the savings. We have therefore delayed the savings to start in 2015 rather than 2014. In addition we have modified the approach for these savings to be an overall saving of 12% of total modelled costs for each company. This equates to £134,686 savings over the three years of the control for PNGL. This is a higher percentage of the overall savings between the two companies which we consider more equitable than our original proposal.

5.71 The combination of call volumes and the cost per call generated by the model results in an increasing trend in total call centre costs. However, PNGL's forecast trend indicates a significantly greater increase.

5.72 The allowances are shown in the table below along with PNGL's submission

Table 19 – Emergency call centre workloads and costs for PNGL

Cost element	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergency Calls (no.)	29,914	36,020	37,698	39,420	36,694	37,691	38,628
Cost per Emergency Call (£)	*15*	*17*	*16*	*16*	*15*	*13*	*13*
Total Emergency Call Centre Cost (£k)	460	596	620	644	540	486	496

Source: PNGL and the Utility Regulator

Emergencies (First Call Costs)

5.73 PES provides a first call response service to PNGL with an associated level of fixed cost. There is a degree of flexibility in the workload/deployment of PES manpower which results in less non-productive time compared with an arrangement based simply on provision of dedicated First Call Operatives (FCOs) engaged on emergency response only. In the draft determination our view was that PNGL's costs were therefore driven mainly by the level of operational activity rather than the fixed costs of service provision. However we have reviewed the data further and have now concluded that we should consider higher levels of fixed costs than originally anticipated.

5.74 Similar to call centre costs, the principal driver for emergency activity is the total number of customers connected to the network. Rune developed a model to determine appropriate allowances for emergency costs. Further details on the model are included in Appendix 2.

5.75 PNGL forecasts a slight reduction in the number of emergency jobs per 10,000 customers; however Rune believes that the trend should indicate a greater reduction. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that are initially likely to generate a higher level of emergency workload.

5.76 PNGL's total first call emergency actual costs show a reducing trend over the period 2010 - 2011, however, PNGL has forecast a substantial rising trend in the forecast period. The model also generates a rising trend in the forecast period, but at a slower rate. When taking account of the additional customers we expect PNGL to connect over the period, the total costs determined is at a similar level to those requested by PNGL before subsidiary company profit is considered.

5.77 PNGL contracts with its subsidiary company, PES, for the provision of emergency FCOs. In line with previous policy, we have decided to disallow profit margins of any related party. Therefore, the profit margin on PES-related emergency and maintenance activity has been removed.

5.78 We have assessed the PES profit element based on its 2011 Kellen accounts and have determined that 14% of the costs relating to PES activities will be removed as we believe this represents the profit element of the contract. Our assessment of these costs is shown in the following table. With the profit element removed, we have determined allowances of c. £1.4m per annum to PNGL for First Call Emergency work.

Table 20 – First call emergency workload and cost information for PNGL

Cost element	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergencies (no.)	15,156	18,200	19,048	19,918	18,449	18,951	19,421
Cost per Emergency Job (£)	*100*	*86*	*86*	*86*	*89*	*89*	*88*
Assessed Emergency Cost (£k)	1,512	1,566	1,634	1,703	1,643	1,678	1,711
PES Profit Element (£k) (14%)					230	235	240
Total Emergency Cost (£k)	**1,512**	**1,566**	**1,634**	**1,703**	**1,413**	**1,443**	**1,471**

Source: PNGL and the Utility Regulator

Repair Activities

5.79 Repair costs result from either gas escapes from main or service pipes due to joint problems (condition problems) or third party interference damage.

5.80 PNGL has confirmed that the costs reported and forecast are net, i.e. after recovery of costs from third parties, yet PNGL has submitted costs of £20,000 for damage repairs in each year, both in the actual and forecast periods. We expect that the majority of these costs should be recoverable through third parties.

5.81 We note that PNGL has not yet incurred any mains or service condition repair costs. PNGL have identified that additional new costs for valve chamber inspections are required and we have accepted these costs. We have taken the average costs for damage repairs (net) for 2010 and 2011 and rolled these figures forward to the period 2014-2016 with the addition of valve chamber costs.

5.82 The determined cost allowances for repair activity are detailed in the following table.

Table 21 – PNGL total repair costs, £k

Cost element	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Total Repair Cost (£k)	42	86	88	91	79	80	80

Source: PNGL and the Utility Regulator

Maintenance Activities

5.83 Maintenance activities are those direct activities which are necessary to keep the network in safe working order with the exception of those activities carried out by FCOs and repair teams. In this context, the activities are broad and include disparate activities from repairing telemetry electronics to the maintenance of district pressure reduction equipment.

5.84 This wide range of activities creates great difficulty in undertaking specific activity benchmarking both within NI and across GB. The nature of the costs and activities vary greatly depending on the age, design and nature of the networks being operated.

5.85 The information collected within GD14 has improved the commonality of the data provision by both companies, although it is not at a sufficient stage of maturity to robustly benchmark at the detailed activity level.

5.86 We have therefore taken an approach of reviewing the detailed actual expenditures reported by both companies and setting to one side items considered exceptional (i.e. not a regular and consistent item of expenditure). This expenditure has then been rolled forward from the levels at 2011 through 2012 and 2013 to provide a base level of expenditure in 2014-2016.

5.87 We then looked at adding to this base level of expenditure items which have been identified by the companies as being a justified extra expenditure required in the years 2014-2016. We were not convinced that certain items have been sufficiently justified as expenditure required in the GD14 period; therefore, some items have been excluded from the determined allowances. Additional details on the model, including the principles and assumptions of the model, and details of the costs which have been excluded from the baseline and then added back for 2014-2016 are included in Appendix 2.

5.88 The model uses customer numbers as a primary driver to roll forward the base level expenditure into the forecast years. We also considered that Modern Equivalent Asset Valuation (MEAV)[25] could be used as a driver as this is used by Ofgem in benchmarking GB network maintenance. However, MEAV has not been collected in NI in the run-up to GD14 and could not be expected to be gathered in the timescale required for the GD14 review. We would like to explore the possibility of using MEAV in future controls as a driver for network maintenance activities. Following the approach used in GB, this will require companies to undertake an inventory of their

[25] MEAV is employed by Ofgem as a means of creating an equivalent new network which can be used as a scale driver for various cost activities. MEAV can recognise the size, asset base and complexity of a network, and represents the cost of creating an equivalent new network.

network assets and their replacement values. It is expected that the primary driver would be above ground assets, as this is understood to drive most of the maintenance cost.

5.89 We are satisfied that the use of forecast customer numbers gives a reasonable and fair uplift in the costs to reflect the growth of the network provided the mix of domestic and I&C customers is taken into account.

5.90 We are implementing a change of policy to domestic site works as suggested in the draft determination. We have reviewed the current arrangement in relation to meter exchanges under domestic Supplier Work Requests (SWRs) and have amended the policy to align it with the policy currently in place with FE. Meter exchanges from credit to prepay will continue to be free of charge to the customer (up to a maximum of one exchange per year), and we have granted an allowance for this in this price control. However, going forward, no allowance is being granted to PNGL in relation to prepay to credit meter exchanges and therefore under the new policy, domestic consumers will no longer be entitled to a free meter exchange from prepay to credit. It is important to emphasise that PNGL will not be required to cover the cost of the meter exchanges where no allowance is provided in the price control. PNGL would charge the cost of the exchange to the appropriate supplier or customer. Therefore, this reduction in the overall maintenance costs is not directly comparable with historical maintenance costs.

5.91 In the draft determination we proposed to provide an exception for vulnerable customers by providing an allowance to PNGL to cover prepay to credit meter exchanges for vulnerable customers. However, having considered this further, we do not believe it is appropriate to make this exception under the distribution price control. We note that gas suppliers have licence obligations in relation to vulnerable customers[26] and therefore we believe it would be more appropriate that suppliers make exception for vulnerable customers to allow one free prepay to credit meter exchange per year where appropriate to do so. Therefore, for the avoidance of doubt, we expect gas suppliers to not pass on charges for meter exchanges to vulnerable customers. We note that the price control for the regulated gas supply company in Greater Belfast already includes an allowance to cover domestic meter exchanges.

5.92 For the final determination, we have considered an appropriate timeframe for implementation of the new policy and we have decided that it will take effect from 1 April 2014. We have granted PNGL an additional allowance to cover meter exchanges during the first three months of 2014. This three month period will allow PNGL and gas suppliers adequate time to implement the change of policy. We note that gas suppliers will be required to review and where appropriate amend their codes of practice and PNGL's connection policy will need to be reviewed to ensure it reflects the change of policy.

5.93 In the final determination we have granted PNGL the requested allowance to replace telemetry equipment at key sites during the GD14 period. We note however that PNGL has not provided a detailed cost benefit analysis in relation to the telemetry project and we therefore expect PNGL to produce a detailed report at the end of 2015 describing the work carried out, and detailing the benefits and costs incurred. We will consider this at the next price control. We also note that FE is also seeking to upgrade its telemetry systems in the GD14 period and we therefore expect PNGL and FE to work together to find the most efficient and beneficial solution.

[26] A vulnerable customer is as defined in the gas supply licences: as domestic consumers who is: (a) of pensionable age; (b) disabled, including in particular domestic consumers who are disabled by virtue of being blind, partially sighted, deaf or hearing impaired; or (c) chronically sick.

5.94 In the draft determination, we proposed that a 10% efficiency would be applied to the baseline maintenance costs in each year in recognition that PNGL is in all likelihood still not operating to the most efficient maintenance schedule. In PNGL12, we also applied a reduction of 10% in respect of network and meter maintenance but stated that we were prepared to increase this in the 2014 review if PNGL did not develop an asset risk management system such as PAS55. We are pleased to note that PNGL has now commenced work on the development of a comprehensive asset management system based on the principles of PAS55 and incorporating Reliability Centred Management (RCM) techniques. For GD14 we have decided to remove the 10% efficiency target from the maintenance allowance. However we wish to be clear that we expect PNGL to continue with the implementation of their asset management system and we expect a detailed update on this at the next price control. At the next price control if we do not believe RCM has been fully implemented, we will re-examine this area and may introduce the efficiency target again.

5.95 As outlined earlier, we have decided to disallow the profit margin on all PES activity. PNGL's contract with PES is primarily for the provision of emergency FCOs; however, based on the information PNGL has provided, the FCOs also carry out planned meter work for domestic and small commercial consumers (for example, battery changes and meter exchanges). We have therefore disallowed the 14% profit margin from the maintenance activities, which are completed by the FCOs.

5.96 The table below shows a comparison between the allowance requested by PNGL and the determined allowance when the PES profit margin has been removed from the appropriate maintenance activities.

Table 22 – PNGL maintenance costs, £k

Cost element (£k)	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Total Assessed Maintenance Cost	1,879	2,401	2,631	2,336	1,941	2,016	2,081
Assessed Maintenance Cost (PES Related)	1,323	1,686	1,778	1,724	1,428	1,388	1,514
Assessed Maintenance Cost (other)	556	716	853	612	513	627	567
PES Profit Element (14%)					-200	-194	-212
Allowance	**1,879**	**2,401**	**2,631**	**2,336**	**1,741**	**1,821**	**1,869**

Source: PNGL and the Utility Regulator

Summary of Emergency & Network Maintenance Costs

5.97 The following table provides a summary of the determined allowances for emergency and network maintenance activities. For comparison, the table also provides the average historical actual costs for 2010 – 2011 and PNGL's forecast submission for 2014 – 2016.

Table 23 – PNGL emergency & maintenance costs, £k

Cost element (£k)	Average 2010-2011	PNGL Submission				Final Determination				Difference	
		2014	2015	2016	Total	2014	2015	2016	Total	Total	%
Call Centre Costs	460	596	620	644	1,860	540	486	496	1,522	-338	-18%
First Call Costs	1,512	1,566	1,634	1,703	4,903	1,413	1,443	1,471	4,327	-576	-12%
Repair Team Costs	42	86	88	91	265	79	80	80	240	-26	-10%
Maintenance Activities	1,879	2,401	2,631	2,336	7,369	1,741	1,821	1,869	5,431	-1,938	-26%
Total Direct Opex	3,894	4,649	4,973	4,774	14,397	3,773	3,830	3,916	11,519	-2,878	-20%

Source: PNGL and the Utility Regulator

Insurance

5.98 In the draft determination we stated that PNGL had requested £1.03m, £1.06m and £1.08m in 2014, 2015 and 2016 respectively. In their consultation response, PNGL highlighted that its insurance cost line from 2010 onwards had been erroneously overstated and its fleet cost line understated by the corresponding amount due to an allocation error in the credit associated with cars used by Phoenix Energy Services (PES). PNGL's historic actual costs and requested costs for the GD14 period have therefore reduced for the final determination.

5.99 PNGL's revised requested allowances are £0.98m, £1.01m and £1.04m for insurance in 2014, 2015 and 2016 respectively. This includes the costs of business insurance (i.e. insurance for the gas network, public liability, etc.), car insurance and building insurance. According to PNGL's data, business insurance accounts for 91% of the total requested allowances, while car and building insurance account for 8% and 1%, respectively. PNGL's insurance costs decreased year-on-year between 2007 and 2009, but increased in 2010 before falling again in 2011. Over this period, PNGL's insurance costs were highest in 2007 at £812k. In 2012, PNGL's costs increased to £786k and PNGL has forecast another increase for 2013.

5.100 The main element of PNGL's insurance costs is business insurance, which in turn is dominated by business interruption and public liability, and to a lesser extent employer's liability insurance. PNGL states that these costs are assumed to be driven by changes in company turnover and therefore would need to be calculated on the basis of the final allowable income derived.

5.101 As stated above, PNGL's requested car insurance costs have reduced since the draft determination. For car insurance costs, PNGL has now requested an allowance of around £1,200 per annum for each company car. PNGL has requested this allowance for 68 company cars in 2014 and 2015 and 66 cars in 2016. In 2012, PNGL had a total of 64 company cars and in 2013 this number has increased to 66.

5.102 The business insurance costs requested by PNGL represent a significant increase on historical premiums. For example, the increase between 2012 and the request for 2016 is over 30%. We do not have any evidence to warrant such an increase and believe PNGL can negotiate lower premiums.

5.103 PNGL has stated that that there are risks associated with its insurance costs, in particular the premiums related to business interruption, which are very specific to the PNGL network. However, this does not provide a sufficient rationale for why premiums are expected to increase over time in relation to the same (or even slightly expanded) PNGL network. We also note that the historical trend for actual insurance costs has not increased year on year.

5.104 In the absence of adequate justification warranting the magnitude of the claimed increases in business insurance, we have continued with the approach of granting a business insurance allowance based on a 3-year average of the actual costs incurred during 2009 – 2011.

5.105 It should be noted that in PNGL12, we adopted the approach used by Ofgem to base business insurance costs on 1.04% of turnover. We have decided not to use this approach to set allowances for PNGL in the GD14 period as doing so would result in significantly lower allowances than using the 2009 – 2011 average.

5.106 PNGL's requested allowance for car insurance has reduced from £1,905 per annum per car to around £1,200 per annum per car. Despite this reduction of about £700 per car, we still consider this to be unreasonably high. As stated in the draft determination, the AA's average premium for annual comprehensive car insurance in 2013 is £750. We expect PNGL to be able to negotiate competitive rates for a fleet of cars and therefore we are continuing to grant an allowance of £750 per car in the final determination to an assumed fleet of 66 cars (consistent with the number of cars in 2013 and again in 2016).

5.107 Finally, for building insurance costs, we have granted allowances on the basis of a 2 year average of the actual costs for 2010-11.

5.108 Our determined allowances for 2014 -2016 are shown in the table below along with PNGL's revised requested allowances and the variance between the two. We note that the determined allowances shown in this table are higher than the final allowances shown in the PNGL opex summary table at the end of this section as we have apportioned an element of the insurance allowance to be recovered through the Connection Incentive Mechanism.

Table 24 – PNGL insurance costs, requested and allowed, £k

	2014	2015	2016
PNGL requested allowances	984	1,012	1,037
Final Determination	711	711	711
Variance	-273	-301	-326

Source: PNGL and the Utility Regulator

Manpower

5.109 PNGL has requested an annual allowance of between £5.35 million and £5.45 million for the 2014-2016 period.

5.110 By comparison, historical actual costs for 2008-2012 were between £4.3 million and £4.7 million per year. PNGL has forecast a step change increase in 2013 compared to 2012 actuals and this increase continues into the GD14 period. The following table shows PNGL's historical manpower costs (including estimates for 2013) compared to allowances we have determined in the two previous price controls.

Table 25 – PNGL manpower allowances and actual costs, £k

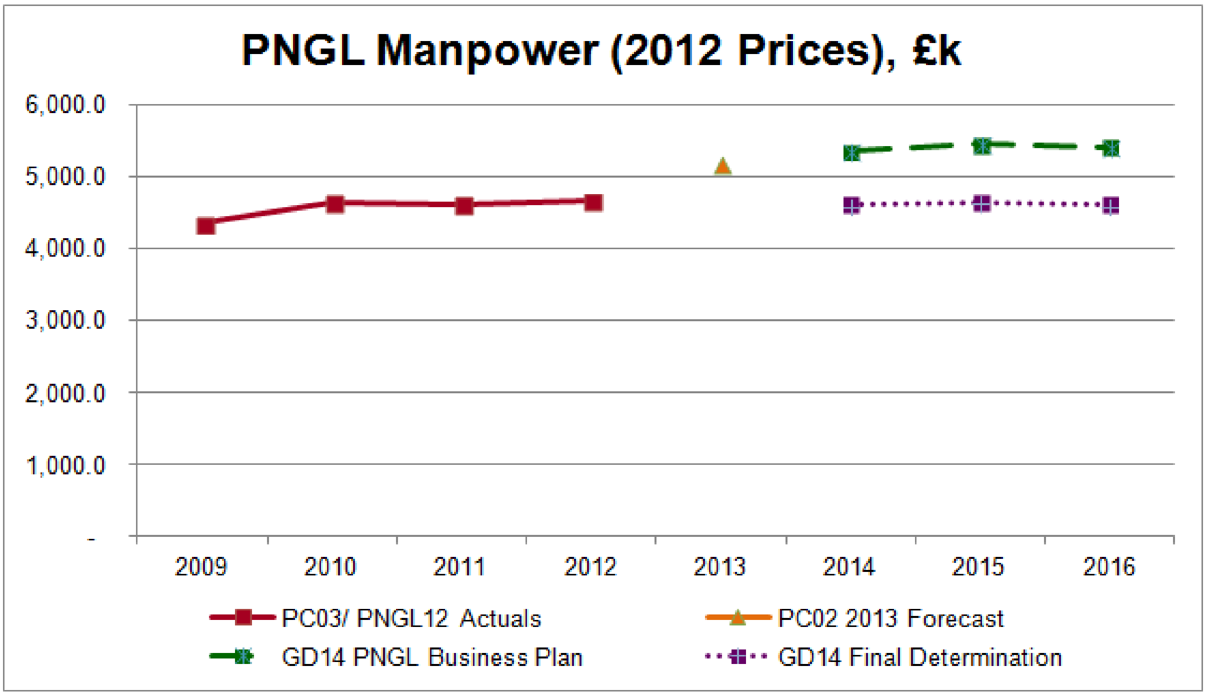
	PC03				PNGL12	
	2008	2009	2010	2011	2012	2013
Final determined allowances	4,836	4,748	4,647	4,565	3,894*	3,910*
Amounts recoverable under A+M+PR					768	782
Total allowances	**4,836**	**4,748**	**4,647**	**4,565**	**4,662**	**4,692**
Actual costs (2013 is best available)	4,325	4,343	4,638	4,612	4,657	5,170

* These are the fixed manpower allowances for 2012 and 2013. However, an element of manpower costs was also recoverable under the A+M+PR mechanism introduced with PNGL12 as shown in the table.

Source: PNGL and the Utility Regulator

5.111 The following line graph displays PNGL's manpower costs from 2007 to 2012. It also shows PNGL's best estimate for 2013 costs and their forecast costs for GD14. The graph compares this to the final determination allowances for 2014-2016. The allowances shown in the graph include the amounts which have been removed from manpower to be recovered through the Connections Incentive Mechanism in order to provide a like-for-like comparison.

Figure 10 – PNGL manpower historical costs including Connections Incentive Mechanism and GD14 Submission, £m



Source: PNGL and Utility Regulator

5.112 PNGL provided a detailed build-up and explanation of its forecast manpower costs, permitting us to undertake an in-depth analysis of the submission and to complement the thorough review completed as part of the PNGL12 price control.

5.113 When reviewing the manpower submission, we assessed whether the level of staffing resources requested by PNGL is appropriate for operating and maintaining its network and the level of remuneration across the job grades.

PNGL staffing resources

5.114 Since the PNGL12 price control, PNGL has been reorganised into three main departments as follows:

- **Commercial operations –** this department is responsible for the safe, reliable and efficient operation of the network and now also includes the regulatory affairs function.
- **Business development –** this division is mainly responsible for sales and customer service, including marketing and PR.
- **Finance –** this department provides corporate support functions including finance, human resources and IT support, as well as revenue protection and business planning.

5.115 PNGL's senior management team consists of four executive directors, namely a Chief Executive Officer (CEO) and the heads of the three departments above i.e. Director of Commercial Operations, Director of Business Development and Director of Finance.

5.116 The table below sets out total FTEs in post and those forecasted by PNGL. For 2012 and 2013, PNGL has provided best available information and estimates, respectively. The majority of the FTEs are employees of PNGL; however a small number of agency staff are also included in their total staffing complement.

5.117 PNGL's GD14 submission estimated 131.4 FTE in 2012 and estimated a cost of £4.9 million for manpower in 2012. PNGL have since provided the updated actual cost for manpower in 2012 which is £263k less than the estimated cost, but it is important to note that we have not been provided with the corresponding updated actual number of FTE employed in 2012.

Table 26 – PNGL staffing complement (FTEs), historical and requested

Department	*2009*	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*
		Actuals		*Best available / Estimate*			*Requested*	
Senior management	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Commercial operations	45.8	49.3	51.3	50.0	51.5	53.0	53.5	53.0
Business development	37.8	40.3	42.6	45.3	47.5	48.0	48.5	48.0
Finance	30.4	31.7	33.1	32.1	29.8	29.8	28.8	28.8
Total (including agency)	**118.0**	**125.3**	**131.0**	**131.4**	**132.8**	**134.8**	**134.8**	**133.8**
Recharges to PES & Supply	12.2	10.9	11.1	10.1	8.3	6.8	5.3	5.2
Total exc. Recharges	**105.8**	**114.4**	**119.9**	**121.3**	**124.5**	**128.0**	**129.5**	**128.6**

Source: PNGL

5.118 The table highlights that PNGL has forecast a substantial increase in FTE in the GD14 when the staff recharged to Phoenix Energy Services (PES) and the supply business are removed.

5.119 In assessing the manpower requirements, it is important to note that as part of the sale of the supply business to Airtricity[27], PNGL entered into a Service Agreement to provide some shared services to Airtricity on an interim basis. Most of the services provided under this arrangement were for a period of 3 or 6 months and have therefore ceased, however PNGL will continue to provide IT support and facilities management until mid-2014. PNGL's manpower recharges to the Supply Company will therefore cease in 2014.

5.120 The reorganisation of PNGL has created some difficulties for us in gauging trends in the number of full-time equivalents (FTEs) within each department. However, our interpretation of the information provided is that PNGL has forecast a substantial increase in FTE for the Distribution business in the GD14 period when the staff recharged to Phoenix Energy Services (PES) and the supply business are removed.

5.121 PNGL has provided justification for 1 additional FTE in 2014 and 2015 to facilitate the introduction of the new asset management system. PNGL advises that this FTE will not be needed in 2016. PNGL has also requested an additional 0.5 FTE per year in both the customer services and transportation services departments and explained this increase was as a result of the growing business.

5.122 PNGL has requested an allowance for 3.8 agency staff in each year of the GD14 period. We have provided no explicit allowance for agency staff in the determination, thereby reducing the determined number of FTE by 3.8, compared to the requested number of FTE. The reason for this decision is that PNGL forecast a substantial increase in FTE (including agency staff) for the distribution business in the GD14 period compared to 2012. The final determination now allows 124.2, 125.7 and 124.8 FTE for the distribution business in 2014-2016 respectively. PNGL may continue to employ a number of agency staff if they believe this is beneficial; however we expect PNGL to fund the cost of agency staff through the general manpower allowance and the number of staff including agency should be in line with the determined FTE numbers stated above.

5.123 As set out in the Connection Incentive section of this paper, we are continuing with a per connection opex allowance for new owner occupier (OO) connections. We described how this mechanism will replace all sales-related costs directly attributable to new OO connections. Hence, a significant element of the manpower costs will be removed to be recovered through the connections incentive mechanism.

Remuneration levels

5.124 PNGL provided a detailed build-up of the remuneration offered to its staff. In order to inform our determined allowances, we have reviewed these remuneration packages and have compared against the PNGL12 determination at which time we had conducted a similar review with the assistance of remuneration consultants and the employment of benchmarking.

5.125 PNGL has incorporated a real 1% salary increase in its submission for 2014 and 2015. We do not consider that an increase of 1% above RPI is justified; therefore we have disallowed the requested increase for 2014 and 2015.

5.126 Additionally we find that the requested remuneration levels for the senior management team exceed the packages typically observed in similar industries and

[27] In June 2012, PNGL sold the entire issued share capital of its gas supply business, Phoenix Supply Limited, to Airtricity Energy Supply (Northern Ireland) Ltd. The supply business was subsequently renamed Airtricity Gas Supply (NI) Ltd (**"Airtricity"**).

business types. Hence, we have retained remuneration for this team at the levels determined in PNGL12 and rolled forward.

5.127 PNGL provided a hard-coded value for Employer's National Insurance Contributions (NICs). We recalculated the NICs using the determined remuneration levels as a driver. This resulted in a lower amount allowed for Employer's NIC than that requested by PNGL.

5.128 In response to the draft determination, PNGL suggested that the manpower proposals in the draft determination were entirely inconsistent with actual costs incurred. We do not agree that this is the case and we consider that this is evident from the graph shown in Figure 8 at the start of this manpower section. We consider that the determined allowances are appropriate given that the actual costs incurred historically include higher remuneration packages for the senior management team than comparator organisations.

5.129 Finally, as stated earlier, significant manpower costs have been removed to be recovered through the Connections Incentive Mechanism. These costs can be summarised as follows:

- Costs have been removed from the Business Development department to account for the costs of employing staff who are responsible for OO new connections;
- A small element of the costs of support staff from the Finance department has been removed as some of their costs can be attributed to creating OO new connections;
- We have allocated an element of the NICs to be recovered through the Connections Incentive Mechanism to account for staff who are considered to be responsible for OO new connections.

Summary

5.130 We have determined a fixed manpower allowance of £3.6 million in 2014, 2015 and 2016. The following table shows PNGL's requested allowances for the 2014 – 2016 period compared to the final determination. The amounts removed to be recovered through the Connections Incentive Mechanism are also displayed to enable like-for-like comparison. We note that our assessment of the manpower costs directly related to OO sales has resulted in a higher amount being removed to be recovered through the Connections Incentive Mechanism than in PNGL12.

Table 27 – PNGL manpower costs, requested and allowed, £k

	2014	*2015*	*2016*
PNGL requested allowances	5,351	5,454	5,413
Final Determination	**3,541**	**3,611**	**3,608**
Amounts removed to be recovered through Connections Incentive Mechanism	1,057	1,032	994
Total allowances*	**4,598**	**4,643**	**4,603**
Variance	-753	-812	-810

* The fixed manpower allowances are displayed in the second row of the table. However, to ensure a like-for-like comparison with PNGL's request, total allowances also include the sums recoverable under the Connections Incentive Mechanism.
Source: PNGL and Utility Regulator

Rates

5.131 PNGL has requested an allowance for rates, covering both network and office rates. The amounts requested are shown in the following table.

Table 28 – PNGL requested rates allowances, £k

	2014	2015	2016
PNGL total requested allowances	**1,228**	**1,390**	**1,457**
Network rates	1,097	1,246	1,313
Office rates	239	239	239
Recharged office rates	-108	-95	-95

Source: PNGL

5.132 We have in the past set network rates using a formula which links the allowance to PNGL revenues. PNGL's allowance request was also calculated using the current formula; however, PNGL has requested that network rates be treated as a pass-through cost going forward.

5.133 We are comfortable with the approach of using a formula linked to revenue in order to set the network rates allowances for PNGL. We have used this approach historically in PC03 and PNGL12 and we are retaining it for the present price control. The network rates allowances have therefore been calculated accordingly; however for the final determination we have updated the formula to use the determined revenues from this price control. This is reflected in the final allowance.

5.134 For office rates, PNGL has requested £239k per annum before recharges. PNGL recharges elements of its office rates to capex, PES, Airtricity (and previously PSL) and to another sub-tenant. PNGL's recharges are forecast to decrease from the c.£137k recharged in 2010 and 2011 to c.£95k in 2015 and 2016.

5.135 We consider that PNGL should be able to continue to sub-let sections of its building going forward and therefore the recharges should not decrease substantially.

5.136 Our determined allowances for rates in total for the 2014 -2016 period are shown in the table below along with PNGL's requested allowances and the differences between the two amounts.

Table 29 – PNGL requested and determined rates allowances, £k

	2014	2015	2016
PNGL requested allowances	1,228	1,390	1,457
Final Determination	1,376	1,535	1,605
Variance	148	145	148

Source: PNGL and the Utility Regulator

5.137 As per the treatment in PC03 and PNGL12, the allowance for rates will not be treated as pass-through, but will continue to form part of the retrospective mechanism.

Licence Fees

5.138 Licence fees are apportioned between the distribution licence holders according to their share of the total forecasted gas volumes conveyed in their respective areas for the year to which the fees relate. We treat licence fees as pass-through and therefore retrospectively adjust them to reflect the actual fees levied on PNGL by our office.

5.139 For the purposes of setting an *ex ante* allowance, we take the total cost to be apportioned to the two distribution licence holders, namely £163k per annum and use our determined volumes for each year of the price control to split the fee between PNGL and FE. In general, PNGL is expected to convey about 70% of total forecasted NI volumes and therefore the determined licence fees for PNGL are about £114k in each of the control period years.

Office Costs

5.140 PNGL has requested £544k, £595k and £630k (an average of £590k) for the three respective years of the price control, representing a significant increase on office cost allowances we have determined in the recent past.

5.141 As part of PNGL12, office costs were assessed on a 'smaller item' basis in setting determined allowances. In GD14, we requested more disaggregated information from PNGL subsequent to its initial submission to allow a more detailed review of individual categories where necessary.

5.142 Our review of the disaggregated information received outlined a claim for a 15% rise in rental for the Airport Road West (ARW) Offices in 2015 as well as an increase in relation to the loss of the Airtricity sublet in mid-2014. Neither of these requests have been granted and overall final allowances equate to £437k, £468k and £469k (prior to connection incentive mechanism reductions), giving an average of £458k over the price control period.

5.143 A review of PC03 actual costs from 2009 to 2011 shows an average spend of £448k (in 2012 prices), therefore, the draft allowances are comparable and reasonable on this basis.

Information Technology

5.144 PNGL has requested an average allowance of £314k per annum for 2014-2016, compared to an actual average of £211k per annum in the period 2007-2011 and determined allowances of £201k per annum for PNGL12. For 2012, PNGL estimates its actual IT costs at £250k and thereafter assumes that IT costs move with inflation, with the exception of an incremental increase in 2013 associated with the development of its 'Concerto' system[28].

5.145 We commissioned consultants, Gemserv, to advise on the appropriateness of PNGL's allowance request. Gemserv was asked to examine both recent actual expenditure on IT compared to determined levels and to assess whether the future requested allowances were appropriate and justifiable. Further, Gemserv undertook benchmarking with comparable GB organisations (to the extent that this was feasible) and also took into account the possible impacts of changes in the NI industry ownership structure (as this could impact on IT costs).

5.146 Overall, Gemserv's conclusion regarding PNGL's IT opex allowances is that: "*Despite our general view that an increase in the level of IT Opex costs is justified we do not agree that the full allowance requested by PNGL is reasonable*." Key reasons cited include:

- While the size and complexity of the Concerto system has increased with the introduction of supply competition, the development costs associated with this system have been separately reimbursed and therefore the level of allowances associated solely with the maintenance and general support of the expanded systems are excessive, notwithstanding the added complexity of the Concerto system;
- PNGL has sought to recover costs that were previously recharged to PSL – Gemserv's view is that it may be inappropriate to allocate these costs to the regulated business and therefore NI gas customers; and
- The cost of accessing Ordnance Survey of Northern Ireland information appears to be disproportionate when compared to the overall costs, particularly as PNGL only requires access to information relating to the Greater Belfast area. There may, therefore, be grounds for PNGL renegotiating this cost.

5.147 We have accepted the findings of the consultant's report and consequently set IT final allowances at approximately £239k per year consistent with Gemserv's recommendations. This is slightly higher than the average actual spend for PC03 years 2009 to 2011 of £217k (in 2012 prices) per annum.

Professional and Legal Fees

5.148 Professional and legal fees cover consultancy costs and legal fees relating to finance, engineering, health and safety, competition, human resources and regulation. It also incorporates audit and accountancy fees, fees relating to rating agencies and the cost of PNGL's non-executive directors.

5.149 Historically, our determined allowances for this cost category averaged around £350k between 2009 and 2011. There was an exception to the determination in 2012, when

[28] Concerto is PNGL's IT system. PNGL also assumes an upgrade of the Finance system, but this is planned for 2017 and therefore is now outside the GD14 period.

the final determined allowance was in fact £1.758 million because the Competition Commission granted PNGL an additional amount to cover some of its costs associated with the PNGL12 referral.

5.150 PNGL has requested £670k, £633k and £632k for professional and legal fees in 2014, 2015 and 2016, respectively. PNGL stated that it used its estimated 2013 outlay as a baseline. However, the requested allowances far exceed those we have granted in the past (excluding exceptional items such as the costs related to the CC referral) and the average actual historical costs reported by PNGL (over a reasonable time to smooth out annual fluctuations). The request is also higher than that submitted by PNGL in the previous price control.

5.151 PNGL has provided a breakdown of its requested allowances. According to PNGL's submission, professional and legal fees have averaged £686k in the last three years (2010-2012), excluding all costs relating to the CC referral. However, the costs for 2011 (£897k) are significantly higher than other years (thereby raising the historical average for the last 3 years), but we have not been provided with a sufficient explanation for this.

5.152 In light of the above, we consider that basing future allowances on historical actual costs for the 2010-2013 period would be unsound. We are therefore rolling forward the allowances granted in the PNGL12 determination for professional and legal fees in 2014 – 2016 as the baseline.

5.153 PNGL has also requested one-off costs during 2014 for work required as a result of IFRS reporting and to support revision of the pension scheme due to auto-enrolment changes. We accept that some costs will be required in relation to IFRS reporting requirements and have granted PNGL an additional allowance of £16k in 2014 for this, as requested. However, we consider that any costs related to the pension scheme revisions should be covered in the baseline allowance and therefore no additional allowance is granted.

5.154 Our determined allowances for 2014 -2016 are shown in the table below along with PNGL's requested allowances and the variance.

Table 30 – PNGL requested and determined allowances for professional and legal fees, £k

	2014	2015	2016
PNGL requested allowances	670	633	632
Final Determination	428	412	412
Variance	-242	-222	-221

Source: PNGL and the Utility Regulator

Smaller items

5.155 The residual PNGL cost lines shown below amount to approximately 5.8% of total claimed opex allowances (as restated):

~~Advertising, marketing and PR~~	**Human resources**	~~Manpower~~	~~Rates~~
Billing	~~Incentives (for customers)~~	~~Network maintenance~~	**Stationery**
~~Emergency costs~~	~~Information Technology~~	~~Office costs~~	**Telephone and postage**
Entertainment	~~Insurance~~	**Own use gas**	**Travel and subsistence**
Fleet costs	~~Licence fees~~	~~Professional and legal fees~~	

5.156 In general, these are treated collectively with the exception of Entertainment for which, as with our PNGL12 decision, we set final allowances consistent with HMRC guidance on non-taxable employee benefits. More specifically, we set a final allowance of £20k per annum, based on offering around £150 per employee. This compares with PNGL's request for £43k per annum.

Collective approach to smaller items

5.157 For the remaining cost lines, we again use a similar approach to that established in PNGL12. At that time, we had considered two main possibilities: (1) applying an average of the most recent actual spend over a desired number of years; or (2) using recent actual spend to determine a trend, and then using this trend to extrapolate forward.

5.158 We had concluded that using a trend is less credible than using an average, since trending tends to exaggerate expenditure anomalies in any one particular year. Furthermore, we argued that there is no evidence to support an assumption that these costs are rising in line with the expanding customer base.

5.159 We have reviewed these arguments again and believe that there is no reason to depart from the approach established in PNGL12. We therefore have set final allowances for these cost lines using an average, and for the purposes of our calculations we have selected the most recent five-year timeframe for which we have audited numbers (i.e. 2007 to 2011).

5.160 The final allowances are shown in the following table.

Table 31 – Small items allowances for PNGL, £k

Cost Item	PNGL submission				Final Determination				Difference			
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total
Billing	214	222	231	**666**	103	103	103	**309**	-111	-119	-128	**-357**
Entertainment	43	43	43	**128**	20	20	20	**60**	-23	-23	-23	**-68**
Fleet costs	313	314	307	**934**	257	257	257	**772**	-55	-57	-49	**-161**
Human resources	121	117	116	**354**	68	68	68	**204**	-53	-49	-48	**-150**
Own use gas	17	18	18	**53**	14	14	14	**43**	-3	-3	-4	**-10**
Stationery	51	52	53	**157**	36	36	36	**109**	-15	-16	-17	**-48**
Telephone and postage	130	140	142	**412**	86	86	86	**257**	-45	-54	-56	**-155**
Travel and subsistence	71	71	71	**213**	54	54	54	**161**	-17	-17	-17	**-52**
Total	**960**	**976**	**980**	**2,916**	**638**	**638**	**638**	**1,915**	**-322**	**-338**	**-342**	**-1,001**

As mentioned earlier, the following cost lines in the table above are higher than those presented in the final overall opex allowances summary at the end of this section: Fleet costs, Human resources, Stationery, Telephone and postage, Travel and subsistence. A full explanation for this adjustment was provided in the description of the Connections Incentive Mechanism.

Source: PNGL and the Utility Regulator

PNGL Opex Summary Pre-Efficiency

5.161 In the table below we set out a summary of the total PNGL opex allowances pre-efficiency we have determined for 2014, 2015 and 2016.

Table 32 – PNGL opex summary pre-efficiency, £k

Cost Item	PNGL revised submission				Final Determination				Difference				
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total	Total, %
Advertising, marketing and PR	860	829	789	**2,479**	160	160	160	**480**	-700	-669	-629	**-1,999**	**-81%**
Billing	214	222	231	**666**	103	103	103	**309**	-111	-119	-128	**-357**	**-54%**
Emergency costs + Network Maintenance	4,649	4973	4774	**14,397**	3,773	3,830	3,916	**11,519**	-876	-1,143	-858	**-2,878**	**-20%**
Entertainment	43	43	43	**128**	20	20	20	**60**	-23	-23	-23	**-68**	**-53%**
Fleet costs	313	314	307	**934**	209	209	209	**628**	-103	-105	-97	**-305**	**-33%**
Human resources	121	117	116	**354**	55	55	55	**166**	-66	-61	-61	**-188**	**-53%**
Incentives	783	724	666	**2,173**	0	0	0	**0**	-783	-724	-666	**-2,173**	**-100%**
Information technology	305	316	321	**942**	194	194	194	**582**	-111	-122	-127	**-360**	**-38%**
Insurance	984	1,012	1,037	**3,033**	701	701	701	**2,103**	-284	-311	-336	**-931**	**-31%**
Licence fees	128	128	128	**385**	115	114	115	**344**	-14	-14	-14	**-42**	**-11%**
Manpower	5,351	5,454	5,413	**16,218**	3,541	3,611	3,608	**10,759**	-1,811	-1,844	-1,805	**-5,459**	**-34%**
Office costs	544	595	630	**1,769**	356	381	382	**1,119**	-188	-214	-248	**-650**	**-37%**
Own use gas	17	18	18	**53**	14	14	14	**43**	-3	-3	-4	**-10**	**-18%**
Professional and legal fees	670	633	632	**1,936**	428	412	412	**1,252**	-242	-222	-221	**-684**	**-35%**
Rates	1,228	1,390	1,457	**4,075**	1,355	1,512	1,582	**4,450**	127	122	125	**375**	**9%**
Stationery	51	52	53	**157**	30	30	30	**89**	-22	-23	-23	**-68**	**-43%**
Telephone and postage	130	140	142	**412**	70	70	70	**209**	-61	-70	-72	**-203**	**-49%**
Travel and subsistence	71	71	71	**213**	44	44	44	**131**	-27	-27	-27	**-82**	**-39%**
Total	**16,464**	**17,032**	**16,827**	**50,324**	**11,167**	**11,459**	**11,615**	**34,241**	**-5,297**	**-5,573**	**-5,213**	**-16,083**	**-32%**
Potential £ from connections incentive mechanism					2,583	2,583	2,583	**7,748**	2,583	2,583	2,583	**7,748**	**N/A**
Total	**16,464**	**17,032**	**16,827**	**50,324**	**13,750**	**14,042**	**14,197**	**41,989**	**-2,714**	**-2,991**	**-2,630**	**-8,335**	**-17%**

As per the comment under the summary table for smaller cost items, a number of cost lines in the table above may be lower than the allowance stated in the main body of this chapter. This is due to the apportionment of some of the allowed costs to the connections incentive mechanism.

Source: PNGL and the Utility Regulator

PNGL Opex Post-Efficiency

5.162 As detailed in chapter 14, we consider all opex other than licence fees and connection incentives to be controllable. Table 33 provides a breakdown of the total determined PNGL pre-efficiency opex allowances into controllable and uncontrollable opex.

Table 33 – PNGL controllable and uncontrollable opex, £k

PNGL Opex (£k)	2014	2015	2016	Total
Uncontrollable opex: connection incentive, licence fee	2,697	2,697	2,697	8,091
Controllable opex pre-efficiency	11,053	11,345	11,500	33,898
Total opex pre-efficiency	13,750	14,042	14,197	41,989

Source: PNGL and Utility Regulator

5.163 As detailed in chapter 14, we have applied the relevant compound Real Price Effect and ongoing productivity increase factors for each year to the controllable pre-efficiency opex allowance to establish the controllable post-efficiency opex allowance. We have then added the uncontrollable opex to obtain the overall post-efficiency opex allowance. Table 34 provides an overview over the results.

Table 34 – PNGL opex post-efficiency, £k

PNGL Opex (£k)	2014	2015	2016	Total
Controllable opex pre-efficiency	11,053	11,345	11,500	33,898
RPE and ongoing efficiencies	-108	-194	-284	-585
Controllable opex post-efficiency	10,945	11,151	11,216	33,313
Uncontrollable opex	2,697	2,697	2,697	8,091
Total opex post-efficiency	13,642	13,848	13,914	41,404

Source: PNGL and Utility Regulator

6 Operating Expenditure, FE

Update from Draft Determination

6.1 For connections we have updated the allowance to consider further evidence, which resulted in the connection incentive allowance increasing from £480 to £540 per additional connection.

6.2 For network maintenance the main changes we have made in relation to emergencies for the final determination are to defer the target reductions to emergency call numbers and the efficiency savings relating to the call centre contract until 2015. This results in increased allowances for FE over the three year period. For the maintenance activities FE has provided justification for some of the exceptional items that were disallowed in the draft determination and we have increased FE's allowances in this area, e.g. bridge surveys and inspections. We have also removed the 10% efficiency target that was applied to maintenance costs in the draft determination. We have also resolved some cost allocation issues.

6.3 For manpower we stated in the draft determination that fluctuations in the 2009-2011 actual costs, and the lack of explanation provided in the GD14 submission resulted in us using the 2008 actuals as a baseline for the GD14 proposals. FE has now provided more detailed breakdowns of their manpower costs incurred historically and their forecasts for the GD14 period which has allowed us to update our analysis to use 2012 as the basis for determining allowances. We have also updated our manpower analysis to take account of allocations to the supply businesses.

6.4 For office costs we have not been persuaded to deviate from the allowances outlined in our draft document, however, we have adjusted the figures to reflect allocation of costs to the FE supply.

6.5 We have not changed parental recharges but would note that costs for governor maintenance and meter reading are now considered under the network maintenance and emergencies cost line.

6.6 We have adjusted office rates to take account of cost apportionment to the supply businesses.

6.7 Insurance costs have been revised as a result of FE submitting updated costs and also due to costs being removed from their submission as they should have been apportioned to the supply businesses.

6.8 For smaller items we were not persuaded to deviate from the allowances outlined in our draft determination, however we have adjusted the figures to reflect allocation of costs to the FE supply businesses where applicable.

6.9 There has been no change to Fees & consulting or to licence fees

Introduction

6.10 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

6.11 FE categorises its operating expenditure into 11 different cost lines as follows:

Advertising, marketing and PR	**Manpower**	**Network maintenance**
Bank charges	**Office costs (including IT)**	**Training**
Fees and consulting	**Parental recharges**	**Travel and transport**
Insurance	**Professional subscriptions**	

6.12 In assessing the reasonableness of the expenditure claimed by FE for these cost lines, we have followed the approach used for PNGL in the previous section. That is, we first grouped the cost lines into broader categories and then applied what we consider to be an appropriate approach to each. One additional issue for FE is the allocation of costs between its distribution and supply businesses. We discuss our approach to supply costs below.

6.13 We first identify the items that collectively constitute the largest proportion of total operating expenditure and which separately represent a material share of overall claimed costs (typically, 5% or more). We examine these in some detail on an individual basis, using evidence furnished by FE in its original submission and in responses to our subsequent information requests. The relevant cost lines are:

- Advertising, marketing and PR (which is replaced by the connections incentive mechanism);
- Manpower;
- Parental recharges;
- Network maintenance;
- Office costs; and
- Rates - FE includes rates in its office cost expenditure line but, as we point out later, we have dealt with this separately given the magnitude of the claimed allowances.

Together, these items represent almost 90% of FE's claimed allowances.

6.14 Next, we examine cost items that by their nature require individual assessment, although they might not represent a significant component of overall expenditure. This is because they are pass-through items (as is the case with licence fees, which FE includes in its fees and consulting cost line) or there are other specific circumstances applying, as is the case for fees and consulting and insurance where FE's requested allowances significantly exceed historical spending and allowances.

6.15 We have considered the remaining (smaller) cost lines collectively, following again the approach for PNGL.

6.16 We first set out the connection assumptions we have used in our modelling. This is necessary since some opex and capex allowances will vary explicitly with the number of connections, both in the setting of *ex ante* allowances and later in the retrospective adjustments that are made *ex post* once actual connections are known. The way we will make retrospective adjustments is discussed later in Section 15.

Our connection assumptions

6.17 The targets in respect of owner occupied, new build, NIHE and I&C connections were accepted as submitted.

6.18 OO connections of 2,000 per annum were assessed as reasonable, which are in line with the current level of connections.

6.19 Our determined connection targets are set out in the table below.

Table 35 – Determined annual connections for FE

Cost Item	FE Submission	Final Determination
Domestic – OO	2,000	2,000
Domestic –NB	800	800
Domestic – NIHE	1,133	1,133
I&C	100	100
Total	4,033	4,033

Source: FE and the Utility Regulator

Connections Incentive

The market development review (MDR)

6.20 In PCR02 we set 2009 allowances covering advertising, marketing and PR (including customer incentive payments), subject to a re-opener to review market development by the end of that year. We subsequently consulted on a proposed approach to market development in October 2009 and again in January 2010, before formulating our final positions in April 2010.

6.21 Our analysis and methodology at the time emphasised the need for a per connection allowance in order to achieve efficiency in connection acquisition costs. Accordingly, in the domestic owner occupier (OO) and small industrial and commercial (SIC) sectors we replaced market development allowances, for the period 2010-2013 inclusive, with a per connections allowance the value of which would depend on the number of outturn connections. The main price control allowances were retained for the other customer categories for the PCR02 period.

6.22 FE indicated at the time of the MDR finalisation that a simpler incentive mechanism would be welcomed, thus GD14 has allowed us to align both NI GDNs with a common mechanism to reward OO connections. The SIC connections are now separate to the connections incentive mechanism for FE. We also note that there are a range of other resources and schemes available which provide funds towards natural gas conversion and can complement the connection incentive for eligible customers (e.g. Warm Homes Plus scheme[29] and Boiler Replacement Programme[30] funded by the Department for Social Development and a range of schemes funded through NISEP[31] (Northern Ireland Sustainable Energy Programme)). The Warm Homes Plus scheme provides up to £6500 towards installation of a fully controlled energy-efficient oil or gas central heating system where no system currently exists or towards conversion of an existing LPG, solid fuel or Economy heating system to oil or natural gas. The Boiler Replacement Programme provides, depending on income, £400 or £700 towards the replacement of an old inefficient boiler with a more energy efficient one (£500 or £1000 if controls are also installed). The funds available through the NISEP schemes vary depending on scheme and can, in certain cases, provide for installation of a fully funded natural gas heating system with controls.

The connections incentive mechanism

[29] See http://warm-homes.com/ for further details.
[30] See http://www.nihe.gov.uk/index/benefits/boiler_replacement_allowance.htm for further details.
[31] See http://www.uregni.gov.uk/uploads/publications/130501_NISEP_List_of_Schemes_2013-14_2.pdf for further details.

6.23 In order to simplify the mechanism and also to align the approach between the NI GDNs we are adopting the connections incentive mechanism for FE in the same way as it is applied to PNGL.[32]

Mechanism principles

6.24 The principles used in the development of the connections incentive mechanism were outlined in the PNGL opex section of this paper, but for reasons of completeness we also re-state them here for FE.

6.25 The key elements are as follows:

- The opex allowance per connection has been calculated using the formula:

Allowance per connection = (Revenue per connection) – (Direct capex cost per connection)

Where:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period
AND
Direct capex cost per connection = Determined infill cost per OO connection + Determined meter cost + Determined service cost

- We have developed a model around the above formulae using estimates, where necessary, for some key assumptions within the formulae.
- The mechanism will apply only to domestic OO housing (i.e. the per connection allowance no longer applies to SIC customers). We have therefore separately granted a certain level of fixed allowances for sales-related costs that are NOT associated with OO connections.

Revenue per connection

6.26 A reminder of the formula:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

6.27 We have sought to develop a common per connection allowance for both FE and PNGL and therefore adopt similar assumptions for both companies. The assumptions we have used are as follows:

[32] Please refer to the discussion in paragraphs 5.1 to 5.30.

Variable	Assumption
Average consumption (A)	**410 therms per annum (tpa)** This is the approximate average consumption figure for FE
Conveyance tariff (B)	**40 pence per therm (ppt)** This is an estimate of the approximate tariff applicable to domestic customers
Recovery period (C)	**15 years** This is considered a suitable payback period for the recovery of direct connection costs. Thereafter, all future revenues would contribute to the costs of the wider network
Average revenue per annum per OO connection	**£164** Calculated as: (A) x (B)
Net present value (NPV) of average revenue over recovery period	**£1,729** NPV of: (A) x (B) discounted over the years in (C)

Direct capex cost per connection

6.28 A reminder of the formula:

Direct capex cost per connection = Determined infill cost per OO connection + Determined service cost + Determined meter cost

6.29 The assumed capex costs for the purposes of the connections incentive mechanism are summarised below:

Variable	OO customers
Infill cost	£310
Service cost	£666
Meter cost	£217

Allowance per connection

6.30 Using the above figures we have determined an allowance per connection:

Allowance (£) = (Revenue per connection) – (Direct capex cost per connection)

= 1,729 – (310 + 666 + 217)

= 536 (which we will round up to £540)

Allowance application

6.31 The allowance of £540 per connection is intended to cover those opex costs we believe can be directly apportioned to sales-related activities for domestic OO properties. However, the full allowance is not applicable to *all* new OO connections.

6.32 As already discussed for PNGL, we consider that there will be a certain number of OO connections that would occur anyway without any direct marketing or selling to these customers. We describe these connections as “non-additional”. Since FE could in theory avoid any sales-related costs to connect such customers, no allowance will be applicable for these customers. We have assumed (as for PNGL and in line with the assumption of MDR) that 25% of all new connections will fall into this category.

6.33 The total number of forecast OO connections is 2,000 per annum as set out in Table 35. This makes the non-additional connections 500[33].

6.34 All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We plan to review the mechanisms in place to ensure this is the case in the coming months. We expect the GDNs to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas. We will further discuss with GDNs how this should be defined.

What costs are being replaced by the mechanism?

6.35 The relevant opex costs are:

- Advertising, marketing and PR;
- Incentives;
- OO Sales related staff including relevant director; and
- Shared corporate overheads.

6.36 The full allowances requested against the distribution business for these cost items are as follows:

Table 36 – Potential FE costs to be replaced by Connections Incentive Mechanism, £k

Cost item	2014	2015	2016
Advertising, Marketing and PR			
Market development	805	805	755
TOTAL	**805**	**805**	**755**
Incentives			
Domestic	600	600	600
I&C	150	100	50
TOTAL	**750**	**700**	**650**
Sales related staff (incl. Director)	**591**	**565**	**540**
Corporate overheads (apportioned)	**120**	**118**	**116**
TOTAL	**2,266**	**2,189**	**2,061**

Source: FE and the Utility Regulator

6.37 The *Corporate overheads (apportioned)* cost line above refers to a share of overhead costs we consider appropriate to apportion to OO-sales related activity. The costs are:

- Human Resources/Training;
- Insurance (buildings and car insurance);
- IT;
- Office Costs (including stationary, telephone & postage);
- Rates (excluding network rates);
- Travel and subsistence; and

6.38 Corporate support personnel AND their apportioned share of the above costs (staff in the Finance department including the Finance Director and the Chief Executive

[33] For the avoidance of doubt, the non-additional target is fixed at 500 connections, irrespective of actual output connections.

Officer). Our intention is that these costs are recovered via the mechanism. Therefore we have reduced the fixed allowances for these costs items by an appropriate amount. (This explains why for example our determination for "smaller items" set out in Table 52 is slightly higher than that presented in the final overall opex determination summarised in Table 53.)

6.39 We consider that the costs, as set out in the above table, should be recovered through the mechanism but acknowledge that some element of these costs may not be directly linked to domestic OO sales. We have therefore determined a fixed sum against some or all of the above cost lines, in addition to the allowance recoverable via the mechanism.

6.40 The fixed sums we have determined, along with our rationale, are set out in the table below. Note that total costs in our fixed allowances have been rounded to the nearest £k.

Table 37 – FE fixed allowances, £k

Cost item	*2014*	*2015*	*2016*	*Rationale*
Advertising, Marketing and PR				
Market development	19	19	19	We accept that some of these costs will relate to connections other than domestic OOs, so have pro-rated the total cost based on forecast I&C connections.
Corporate affairs	47	47	47	We have allowed a fixed corporate affairs cost in line with the logic applied within PNGL12 for PNGL
TOTAL	**66**	**66**	**66**	
Incentives				
Domestic	-	-	-	Incentives offered to domestics are to be fully recovered via the mechanism.
I&C	10	10	10	£100 incentive allowance per SIC connection for the GD14 price control.
TOTAL	**10**	**10**	**10**	
Sales development department (incl. Director)	**280**	**280**	**280**	Given the nature of the FE customer base, some members of the sales team (incl. the Director) are clearly not exclusively focused on OO domestics.
Corporate overheads (apportioned)	**-**	**-**	**-**	Corporate overheads have already been apportioned therefore no fixed sum is included.
Total	**356**	**356**	**356**	

* Note that total costs have been rounded down to the nearest £k.

Source: The Utility Regulator

6.41 As with PNGL, in order to reinforce FE's incentive to connect customers, we have introduced a reward if FE exceeds a target level of connections that would increase the per connection allowance for additional connections exceeding the target number of connections by the same proportion that the connections target is overachieved. Conversely, a penalty would apply if FE falls short of the target connections that would reduce the per connection allowance for all additional connections by the same proportion that the connections target is underachieved. This under- or outperformance would be capped at +/- 50%[34]

6.42 For the purposes of setting our final allowance, we will use the target connections and will correct for actual connections through the retrospective adjustment mechanism.

[34] For the avoidance of doubt, the minimum allowance that will be achieved equates to £270 per additional connection and the maximum that can be achieved equates to £810 per additional connection.

6.43 To demonstrate how the new incentive mechanism could work, consider the following examples:

- *Outperformance* – the connection allowance is £540 and the target (excluding non-additional) connections is 1,500, but FE outperforms by connecting 1,650 OO customers (excluding non-additional). As the connections outperformance is 10% (= 1,650 / 1,500 – 1), a unit connection allowance of £594 (= £540 x (1+10%)) will be payable for the 150 extra connections gained; the standard allowance of £540 would still apply to the original 1,500 connections. Total allowances would therefore equal £899,100 (i.e. (£540 x 1,500) + (£594 x 150)).

- *Underperformance* – the connection allowance is £540 and the target (excluding non-additional) connections is again 1,500, but FE this time underperforms by connecting 1,350 OO customers (excluding non-additional). As the connections underperformance is 10% (= 1,350 / 1,500 – 1), the unit connection allowance payable will be £486 (= £540 x (1-10%)) for all connections. Total allowances in this case would equal £656,100 (i.e. £486 x 1,350).

Summary

6.44 The connections incentive mechanism is summarised as follows:

- The full allowance is £540 per OO connection, applicable to all new OO connections after consideration of non-additional connections.
- The total aggregate allowance has been calculated by multiplying this allowance by the forecast number of OO connections (excluding non-additionals), less a sum for recharges to FE Supply of £100k per annum.
- The aggregate allowance will be retrospectively adjusted at the time of the next price control using the actual number of connections.
- The allowance per connection could also be retrospectively adjusted according to whether FE achieves the targeted number of OO connections. The proportional increase (reduction) in the allowance will be equal to the percentage of over (under) achievement of the connection target, subject to the +/- 50% cap and collar.
- The allowances to be recovered via the mechanism will replace those costs set out in Table 36. Where an element of fixed allowance is considered appropriate, this has been included in our overall allowances.
- We expect to reduce the full per connection allowance by 50% from 2017 onwards, but this will be subject to review and possible modification, dependent on the outcome of consultation as part of GD17.

Emergency & Network Maintenance Costs

Allocation of Costs in FE Submission

6.45 As stated in the draft determination, we had some difficulty in interpreting how FE's costs are allocated under the four headings within emergency and maintenance costs and therefore some assumptions were made to arrive at the draft determination proposals. We have worked with FE to resolve the allocation issues and have now agreed the allocations. As a result, the allocation of costs between the four headings has substantially changed for the final determination. The main allocation issue in the draft determination was that the emergency retainer and stores costs were allocated to the maintenance cost line instead of emergencies.

6.46 Following discussions and clarifications with FE, we have also reallocated some costs relating to governor maintenance and meter reading from the parental recharges cost line into the maintenance cost line for the final determination.

6.47 In addition, we noted in the draft determination that the emergency and maintenance submission included some costs which are the responsibility of the supply company and do not relate to the distribution company (e.g. firmuscare costs and boiler servicing). We have removed these costs from the FE submission.

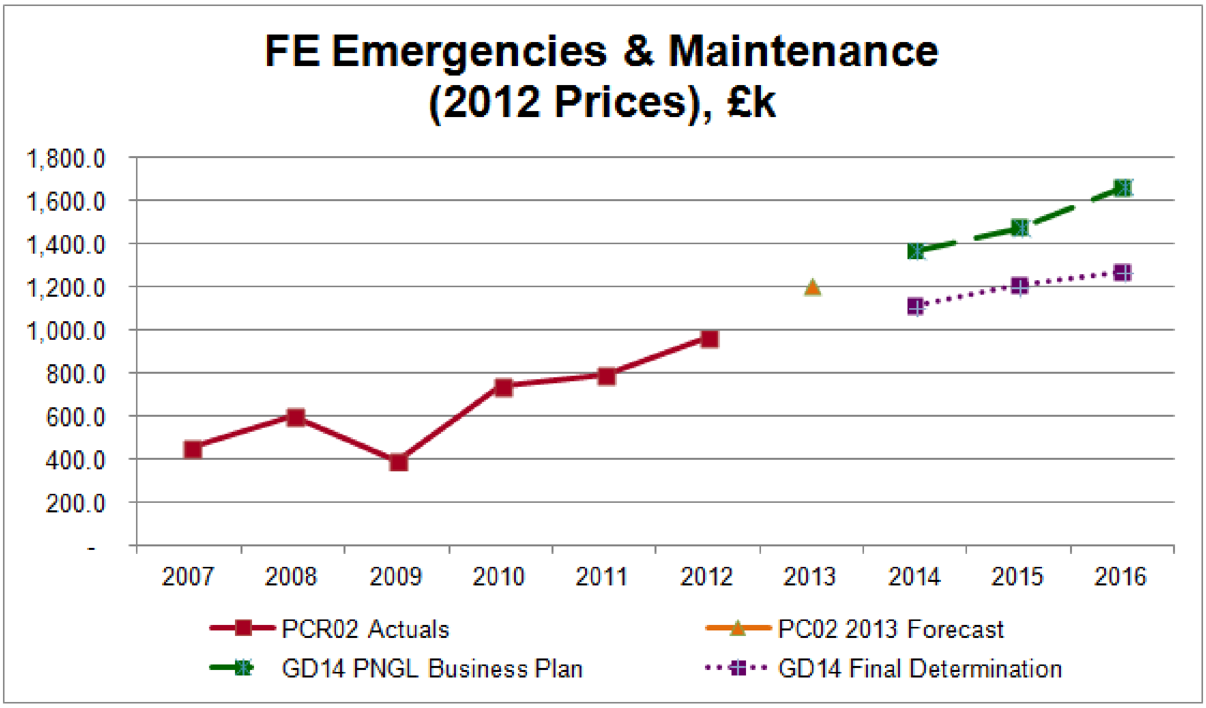
6.48 FE has submitted an additional request for costs relating to meter exchanges which was not included in their original submission. These costs are now included in the FE revised submission.

Overview

6.49 Under the revised submission, FE has requested allowances of £1.4m, £1.5m and £1.7m in 2014, 2015 and 2016 respectively to cover emergency and maintenance costs. For comparison, costs for 2010-2011 averaged around £760k.

6.50 The graph below shows that FE's emergency and maintenance costs fluctuated between c.£400k and c.£1million from 2007 to 2012, and forecast costs for 2013 show substantial increases. These increases extend further into the GD14 forecast period. The graph demonstrates that the determined allowances for 2014 - 2016 follow a trend line from the historical actual costs incurred during 2010 and 2011.

Figure 11 – FE emergency and maintenance historical costs and GD14 Submission, £m



Source: The Utility Regulator

6.51 As with PNGL, we commissioned Rune to advise on the appropriateness of FE's allowance request for emergency and network maintenance costs.

6.52 FE has previously reported its costs and forecasts in terms of the account headings used within its business. To undertake the review for the GD14 price control for both FE and PNGL, we asked Rune to develop a reporting template that would attempt to get both companies to move to a common reporting format and would provide an element of comparability to GB networks.

6.53 Emergency and maintenance costs are reported under the following headings:

- Call centre costs
- Emergencies (First Call Costs)
- Repair activities
- Maintenance activities.

6.54 Illustrative unit rates for comparison purposes in tables are shown in italics; these rates are shown to the nearest £

Call Centre Costs

6.55 Call Centre calls comprise emergency reports that require investigation by a first call operative (FCO) and calls which can be generally categorised as general enquiries and no further action is required. FE requested an allowance of £0.2m per year in 2014, 2015 and 2016 in its submission.

6.56 In line with the approach taken for PNGL, the principal driver for the call centre activity has been established as the total number of customers connected to the network. FE forecasts a flat trend in the number of calls per 10,000 customers, whereas Rune believes that the trend should indicate a reduction. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that may initially generate a higher emergency call rate.

6.57 Rune developed a model to determine appropriate call centre costs for 2014 – 2016. Further details of the model, including the principles and assumptions behind the model have been provided in Appendices 1 and 3.

6.58 The model targets FE to reduce the number of calls received from existing customers by 3% per year and by 1% per year from new customers, starting in 2015.

6.59 The model generated forecasts for the number of calls received (based on number of calls per 10,000 consumers). FE's calls per 10,000 consumers are at a higher level than call volumes that would typically be seen by GB GDNs, despite allowing for additional calls in NI as a result of the large number of prepaid meter problems. In 2010 and 2011, around 50% of the total calls received by the emergency call centre were general enquiry calls. This is an extremely high level of inappropriate calls, and we would expect FE to manage these levels downwards. We therefore consider the target reductions in total call numbers are set at an achievable level.

6.60 An increasing call rate trend has been assumed for the total number of calls, albeit at a lower level than the FE forecast submission. This incorporates the efficiency improvements of between 1% and 3% as outlined above.

6.61 Rune has also formed the opinion that whilst PNGL and FE use the same provider for the call centre, each places its own contract for the provision of emergency call handling and dispatch. It is believed that savings could be made in the cost of procuring this service by PNGL and FE working more closely together. In the event that further licences are granted within NI, it should be possible to extend such savings to any new licence holder.

6.62 In the draft determination we proposed a 50% saving of the fixed modelled call centre costs starting in 2014 (resulting in a reduction of £127,500 for FE over the three years of the control). Following FE's and PNGL's responses to the consultation we continue to believe savings are appropriate; however, after further consideration, we have concluded that time is required for the companies to achieve the savings. We have therefore delayed the savings to start in 2015 rather than 2014. In addition we have modified the approach for these savings to be an overall saving of 12% of total modelled costs for each company. This equates to £42,939 savings over the three years of the control for FE. This is a lower percentage of the overall savings between the two companies which we consider more equitable than our original proposal.

6.63 The determined allowances for call centre costs are detailed in the following table.

Table 38 – FE emergency call centre workloads and costs

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergency Calls (no.)	2,772	6,213	7,310	8,339	5,733	6,359	6,859
Cost per Emergency Call (£)	*48*	*24*	*21*	*20*	*29*	*24*	*23*
Total Emergency Call Centre Cost (£k)	133	146	157	167	167	154	159

Source: FE and the Utility Regulator

Emergencies (First Call Costs)

6.64 McNicholas Construction provides a first call response service to FE which has an associated level of fixed cost. Given the domestic customer population is still relatively sparse, these fixed costs are still higher than more mature networks although they are expected to fall as a percentage of the total costs. These high fixed costs do give rise to relatively high cost per emergency.

6.65 Similar to call centre costs, the principal driver for emergency activity is the total number of customers connected to the network. Rune developed a model to determine appropriate allowances for emergency costs. Further detail on this analysis and the model is shown in Appendix 2.

6.66 FE has forecast a step change in the number of emergency jobs per 10,000 customers in 2013 compared to the actual levels reported for previous years. We are not convinced by the robustness of the FE forecasts for the volume of jobs and how they relate to the cost submission. Taking account of the expected fall towards GB levels as the gas market matures, our model generates a reduction.

6.67 FE's actual costs per emergency job show a substantial reducing trend over the period 2009 – 2011 with a further fall in 2012. Their forecast shows a step higher in 2013 & 2014 compared to 2012, followed by slight downward trend to 2016. The model continues the actual trend towards 2016.

6.68 FE's total first call emergency actual costs show an increasing trend over the period 2011 – 2016. The model also generates an increasing trend, albeit at a much lower rate.

6.69 The determined allowances for first call emergency costs are detailed in the following table along with FE's submission for comparison.

Table 39 – FE emergency workload and cost information

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergencies (no.)	1,062	2,905	3,418	3,899	2,883	3,197	3,449
Cost per Emergency Job (£)	*332*	*279*	*267*	*259*	*211*	*204*	*200*
Total Emergency Cost (£k)	352	810	914	1,010	608	654	690

Source: FE and the Utility Regulator

Repair Activities

6.70 Repair team costs result from either gas escapes from main or service pipes due to joint problems (condition problems) or third party interference damage.

6.71 FE has confirmed that the costs reported and forecast are net i.e. after recovery of costs from third parties.

6.72 The repair figures provided by FE are erratic and in some cases negative. We would expect that the majority of repair costs should be recoverable from third parties. Therefore, we have recommended using FE forecasts for 2012 of £7,916 as the allowance for 2014-2016.

6.73 The recommended total cost allowances for repair activity are detailed in the following table.

Table 40 – FE total repair costs, £k

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Total Repair Cost (£k)	12	32	37	42	12	12	12

Source: FE and the Utility Regulator

Maintenance Activities

6.74 Maintenance activities are those direct activities which are necessary to keep the network in safe working order with the exception of those activities carried out by FCOs and repair teams. A wide range of activities are included within maintenance costs, and activities vary greatly depending on the age, design and nature of the networks being operated. This makes benchmarking these activities more difficult.

6.75 We have therefore taken an approach of reviewing the detailed actual expenditure reported by FE and removing exceptional items to create a base level of expenditure. This expenditure has then been rolled forward from the levels at 2011 through 2012 and 2013 to provide a base level of expenditure in 2014-2016.

6.76 We then analysed the exceptional costs items requested for 2014-2016 to identify which costs have been justified to be incurred during the GD14 period. We are not convinced that certain items have been justified as required expenditure for the forecast period and therefore some items have been excluded from the recommended allowances. Appendix 3 provides additional detail on the model developed by Rune and the details of the costs which have been excluded to create the base line and the analysis of the costs to be added back.

6.77 The model uses the number of customers as a primary driver to roll forward the base expenditure for the forecast years. We are satisfied that the use of forecast customer numbers gives a reasonable and fair uplift in the costs to reflect the growth of the network provided the mix of domestic and I&C customers is taken into account.

6.78 Rune also considered that Modern Equivalent Asset Valuation (MEAV)[35] could be used as a driver as this is used by Ofgem in benchmarking GB network maintenance. However, MEAV has not been collected in NI in the run-up to GD14 and could not be expected to be gathered in the timescale required for the review of GD14. We would like to explore the possibility of using MEAV in future controls as a driver for network

[35] MEAV is employed by Ofgem as a means of creating an equivalent new network which can be used as a scale driver for various cost activities. MEAV can recognise the size, asset base and complexity of a network, and represents the cost of creating an equivalent new network.

maintenance activities. Following the approach used in GB, this would require companies to undertake an inventory of their network assets and their replacement values. It is expected that the primary driver would be above ground assets as this is understood to driver most of the maintenance cost.

6.79 In its submission, FE stated that it plans to implement PAS55 during GD14 to ensure the optimal management of its physical assets and to ensure cost savings for consumers are realised. FE indicated in its submission that they would write to us separately on the process and costs involved. We would emphasise that we are not granting any allowance for implementing such a system either in the GD14 price control, or outside it, given that this system should have been part of how FE set up its business and it would be beneficial to FE. We note also that we have not made an allowance to PNGL to implement an equivalent system, and Ofgem has never made an allowance to a GDN for this activity.

6.80 Nevertheless, we support FE's intention and expect FE to implement a comprehensive asset management system based on PAS55 principles that will drive cost effective optimisation of maintenance and replacement policies during the GD14 period and we will expect FE to have adequate processes in place at the next price control review. As explained in the manpower section, we note that we have increased FE's manpower resource to ensure that FE has sufficient resource to carry out the implementation of an appropriate asset management system.

6.81 In the draft determination, we proposed a reduction of 10% to the baseline maintenance costs to reflect that FE has not implemented, or even started to develop an asset risk management system such as PAS55. As noted, our opinion is that FE should have developed such a system from set-up in 2006. We have considered FE's response to the draft determination and welcome FE's intention to implement an asset management system during GD14. We have therefore decided to remove the 10% efficiency target from the maintenance allowance. However we wish to be clear that we expect FE follow through with their plans to implement an asset management in GD14 and we will expect a detailed update to be provided at the next price control. At the next price control if we do not believe RCM has been fully implemented, we will re-examine this area and may introduce the efficiency target again.

6.82 The table below shows the determined allowances for FE's maintenance activities compared with the FE submission.

Table 41 – FE maintenance costs, £k

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Total Maintenance Cost (£k)	268	372	359	436	318	313	338

Source: FE and the Utility Regulator

Summary of Emergency & Network Maintenance Costs

6.83 The following table provides a summary of the determined allowances for FE's emergency and network maintenance activities. For comparison, the table also provides the average historical actual costs for 2010 – 2011 and FE's forecast submission for 2014 – 2016.

Table 42 – FE emergency & maintenance costs, £k

Cost element (£k)	Average 2010-2011	FE Submission				Final Determination				Difference	
		2014	2015	2016	Total	2014	2015	2016	Total	Total	%
Call Centre Costs	133	146	157	167	470	167	154	159	480	10	2%
First Call Costs	352	810	914	1,010	2,734	608	654	690	1,952	-783	-29%
Repair Team Costs	12	32	37	42	111	12	12	12	36	-75	-68%
Maintenance Activities	268	372	359	436	1,167	318	313	338	970	-197	-17%
Total Direct Opex	764	1,361	1,466	1,655	4,482	1,106	1,133	1,199	3,438	-1,045	-23%

Source: FE and the Utility Regulator

Manpower

6.84 In the draft determination, we stated that FE requested £2.1 million, £2.2 million and £2.4 million in relation to manpower. However after the consultation period ended, we received information from FE on supply costs which highlighted that FE had heavily weighted their allocation of manpower costs to the distribution business. We raised this concern with FE and they accepted that their manpower costs were not allocated correctly. FE provided further detail on the costs that should be removed from the distribution costs and allocated to the supply. We used this information from FE to revise their actual costs in 2012 and the forecast costs for the GD14 period.

6.85 FE's revised request for manpower is £1.96 million, £2.09 million and £2.27 million in 2014, 2015 and 2016, respectively.

6.86 By comparison, FE's revised actual costs incurred in 2012 were £1.52 million. It is therefore clear that FE has forecast a step change in manpower costs from 2014.

6.87 The table below shows FE's historical manpower costs (and the estimates for 2013) compared to allowances we had determined in the previous FE price control. The graph which follows the table below also displays the historical actual manpower costs incurred by FE and compares these to FE's submission for the GD14 period and our determined allowances. It is important to note that in both the table and the graph, the actual costs shown for 2009 – 2011 and the forecast costs for 2013 still include costs which relate to the supply business and have not been allocated appropriately.

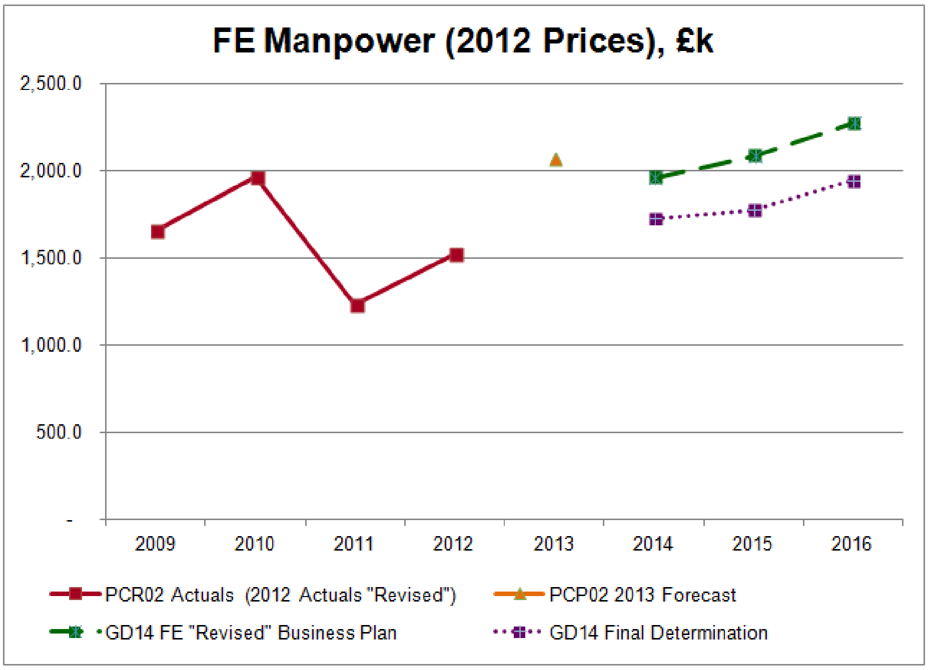
Table 43 – FE historic manpower allowances and actual costs, £k

	PCR02				
	Actuals				Best Available
	2009	2010	2011	2012	2013
Final determined allowances	2,003	1,743*	1,697*	1,542*	1,368*
Final determined allowances with amounts recoverable under Market Development Mechanism included	2,003	1,983	1,937	1,782	1,608
Actual costs (2012-13 are best available)	1,657	1,963	1,230	1,524	2,071

* These are the fixed manpower allowances. However, an element of manpower costs was also recoverable under the 'market development' mechanism introduced in 2010. These are included in the second row.

Source: FE and the Utility Regulator

Figure 12 – FE manpower historical costs including Connections Incentive Mechanism and GD14 Submission, £m



Source: FE and the Utility Regulator

FE staffing resources

6.88 Since the draft determination, FE has provided more detailed breakdowns of their manpower costs.

6.89 FE has informed us that its staffing resources are organised around the following departments:

- **Engineering and maintenance** – this department is responsible for the safe construction and maintenance of the network and for new connections sales to residential customers. It also houses the customer care team, who are engaged on supply activities.

- **Sales and customer operations** – this department is mainly responsible for I&C new connection sales. This department also manages customer switching within the Ten Towns network.
- **Regulation and pricing** – this department is responsible for regulatory relationships and reporting as well as managing transportation services and project management.
- **Finance** – this department provides support functions such as finance, HR and facilities management.
- **Marketing** – this department is responsible for marketing and PR.

6.90 There are also five senior managers employed by FE: the General Manager, Head of Sales, Head of Regulation, Head of Finance and Head of Engineering. However, four of these are responsible for the supply businesses as well as the distribution business and therefore their costs must be apportioned between the businesses. The Head of Engineering is the exception to this as this role relates solely to distribution. Of the entire senior management team, FE has apportioned 1.06 FTE to the supply businesses and the remaining 3.94 FTE to the distribution business.

6.91 The following table shows the actual number of FTE employees that FE has reported were employed by the distribution business during 2009 – 2012, as well as the best available information for the number of FTEs in 2013 and the requested number for 2014-2016.

Table 44 – FE staffing complement (FTEs), historical and requested

	Actuals			Best available		Requested		
	2009	2010	2011	2012	2013	2014	2015	2016
FTEs in distribution (including agency staff)	48	58	48	54.1	60	57.1	59.1	59.1

Source: FE and the Utility Regulator

6.92 In the draft determination we used FE's 2008 actual costs as a basis for setting allowances for the GD14 period. This was due to fluctuations in the 2009-2011 actual costs and the lack of detailed explanation provided by FE.

6.93 As stated above, FE has provided further, more detailed breakdowns of its manpower costs and has also provided information on costs that should be removed and allocated to the supply businesses. For the final determination we have therefore updated our analysis and now use the 2012 actuals as a basis for setting allowances.

6.94 In rolling forward the 2012 actual costs we have included 2 additional FTE in 2015 as requested by FE in order to assist with the extension of market opening to small I&C and residential customers

6.95 We have also completed further analysis into the apportionment of costs to the supply businesses and assessed the number of FTE required based on the forecast outputs.

6.96 In the GD14 period, FE has forecast decreasing numbers of I&C sales connections each year. Therefore we have reviewed the I&C sales team and have reduced the number of sales staff in each year of the GD14 period to correspond to the reductions in sales targets.

6.97 As part of our analysis we also reviewed FE's apportionment of the senior management team to the supply businesses. We do not believe that FE has appropriately allocated these staff based on their responsibilities and we continue to believe that they are heavily weighted towards the distribution business. We have therefore determined revised allocations to the supply businesses for the GD14 period.

Assessment

6.98 In our assessment of FE's manpower requirements we have granted 3 additional FTE in each year of the price control. This is to take account of the business growth since 2012 and will also allow FE to have sufficient manpower resource to undertake their plans to develop and implement an asset management system for network maintenance in the GD14 period

6.99 Based on this analysis, for the final determination we have granted an allowance for 54.4 FTEs in 2014 for the total distribution business, 55.9 FTEs in 2015 and 55.45 FTEs in2016.

6.100 Regarding capitalisation, FE has proposed that this should be reduced throughout the GD14 period, as the distribution business will see a shift away from the engineering emphasis with FE gradually moving from the network build phase to placing a greater focus on network maintenance. We have accepted FE's proposed percentage reductions for the capitalisation of manpower costs, specifically, 32%, 31% and 25% for the respective years of the GD14 price control. However we intend to assess this in more detail in GD17.

6.101 In relation to staff remuneration levels, we have used 2012 actuals and rolled these forward in order to determine the allowances for the GD14 period. In line with the approach taken for PNGL's manpower allowances, we have not granted any percentage salary increases above RPI in our determined allowances.

6.102 We have updated the sales and marketing staff costs related to OO new connections that are removed to be recovered through the Connections Incentive Mechanism. We have also removed a small element of the costs of support staff including NICs as some of these costs can be attributed to creating OO new connections.

6.103 In summary, we have determined a fixed allowance for manpower of c£1.4 million in 2014 and 2015 and c.£1.6 million in 2016 as outlined in the following table. The amounts removed from manpower to be recovered through the Connections Incentive Mechanism are also displayed in the table

Table 45 – FE manpower costs, requested and allowed, £k

	2014	2015	2016
FE requested allowances	1,961	2,086	2,276
Final Determination	**1,386**	**1,436**	**1,606**
Amounts to be recovered through the connections incentive mechanism	340	340	340
Total allowances*	**1,726**	**1,776**	**1,946**
Variance	-235	-310	-330

* The fixed manpower allowances are given by the second row of the table. However, to ensure a like-for-like comparison with FE's request, total allowances also include the sums recoverable under the connections incentive mechanism.

Source: FE and Utility Regulator

Office Costs

6.104 Excluding rates (which are treated separately below), FE has requested between £456k and £459k for the three respective years of the price control, representing a significant increase on office costs incurred in the earlier part of PCR02 and continuing an upward trend that appears to have begun in 2011. As a result, we requested more disaggregated information from FE subsequent to its initial submission and have undertaken a detailed review of the individual items that comprise this cost category.

6.105 The major revisions we have made to FE's submitted costs are explained below.

6.106 ***IT support***. FE has requested £61k per annum for IT support from 2014-2016 and this has been agreed as FE have confirmed subsequent to this consultation publication that its parent company no longer uses the IT system the request relates to (FELIVE).

6.107 ***Heat & light, postage and courier, cleaning***. All of these cost lines are set to increase significantly in the last one or two years of PCR02 with the new higher levels extended by FE into its GD14 requested allowances. However, we have not been able to ascertain the rationale for these expected increases and have therefore taken average spend over recent years to determine our allowances.

6.108 ***Other items***. We have removed the 5% uplift in rent claimed by FE. We have also provided lower allowances than requested for a number of less material cost lines such as office rental, security, service charges, stationery and 'other office costs'. Allowances for the remaining categories have been set broadly in line with historical spend (after adjusting for any sudden spikes in cost).

6.109 ***Supply Recharges***. Further information received indicated that there have been cost allocation issues with FE historically and within their submission, therefore, all components of Office Costs (excl Rates and IT) were assessed for necessary recharges to the supply businesses driven by headcount. This information has been adjusted for in deriving our final allowances.

6.110 Overall, we believe that reasonable office costs (Incl IT) final allowances (net of all supply recharges) for the GD14 price control average £267k per annum versus a request of £458k per annum.

Parental Recharges

6.111 'Parental Recharges' are incurred by FE in settlement of the services provided by its parent company, BGE, in relation to the following:

- Central corporate services covering matters such as HR support, training, procurement services (including tendering for the period contract and downstream installers), legal services, treasury / corporate finance and audit functions, maintenance and development of an IT platform, engineering project planning, payments / invoicing, tariff maintenance and billing, customer relationship management, secretariat services and costs associated with establishing and running the Board of Directors, etc.;
- Grid control and transportation services, including engineering maintenance activities and network pressure monitoring;

- Geographical Information System (GIS) support;
- Health and safety support including technical and safety training; and
- Meter Reading.

6.112 FE considers that these services are required to avoid having to employ external consultants and professional services that it feels would be at a higher cost than those incurred via the recharge mechanism. Our focus has been on assessing whether overall the allowances requested appear reasonable.

6.113 In the case of grid control, GIS and meter reading, which collectively account for about one-quarter of all recharges, we have granted the allowances as requested. This is still the case, with the exception of meter reading, which we have assessed separately. The claimed costs for grid control and GIS are generally in line with those of the PCR02 price control.

6.114 For central services costs (accounting for 75% of total parental recharges), FE has requested allowances that significantly exceed previous allowances and historical costs. The average of the claimed allowances for GD14 are over 50% higher than the average for the PCR02 control period, even after taking into account a large budgeted increase for 2013. According to FE*, "The increase in the shared services cost results from the increasing size of the network and our customer base within our licence area, and the additional roles firmus energy has had to undertake in relation to market opening – IT Development, shipper services, grid control etc."*

6.115 FE had put forward similar arguments at the time of the previous price control. While we accept that the expanded network and market opening *may* increase costs in this area, we believe the claimed allowances are not commensurate with the planned network expansion and the expected volume of transactions under the open market. Moreover, FE has not provided sufficient detail or justification for those areas where there may be increased costs (such as financial transactions), while other costs included in this category (such as the Gas Transmission Management System (GTMS) upgrade) seem to be unrelated to the distribution business.

6.116 In setting our allowances for central services, therefore, we maintain the basis of using the same allowances as we previously granted in PCR02 as we have not seen any arguments which would justify significant increases in this cost.

6.117 The table below shows our final allowances for parental recharges together with FE's request and the differences between the two sets of costs.

Table 46 – FE allowances for parental recharges, £k

Cost Item	FE submission				Final Determination				Difference			
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total
Central services	789	710	731	2,230	266	266	266	799	-523	-444	-465	-1,432
Grid control	75	75	75	225	75	75	75	225	0	0	0	0
GIS, Drawing Office & SCADA	146	146	146	438	146	146	146	438	0	0	0	0
Total	1,010	931	952	2,894	487	487	487	1,462	-523	-444	-465	-1,432

Source: FE and the Utility Regulator

Rates

6.118 As discussed above, FE's submission for office costs included rates, but we have decided to treat rates as a separate cost line given the significance of this item in overall FE opex. The FE submission for rates includes the costs for both network rates and office rates.

6.119 Under the previous FE price control and for the purposes of setting the allowances, network rates were calculated using a formula based on forecast revenues. However, the rates were then treated as a pass-through cost. For 2014–2016, FE has used the same formulas to calculate network rates.

6.120 The allowances requested are shown in the following table.

Table 47 – FE requested rates allowances, £k

	2014	2015	2016
FE total requested allowances	**909**	**1,030**	**1,055**
Network rates	898	1,019	1,045
Office rates	11	11	10

Source: FE and Utility Regulator

6.121 In their original submission, FE included £20k per annum to cover office rates. However, after the consultation period ended we received information from FE on supply costs and from this we identified that FE did not allocate any costs for office rates to the supply business, either historically or in the forecasts for the GD14 period. FE accepts this was an error and agrees that it would be appropriate to apportion office costs based on headcount.

6.122 For the final determination, we have continued using the formula approach to set allowances for network rates. Rates will be treated as a cost pass-through, subject to FE demonstrating that it has taken appropriate actions to minimise the valuations. The allowances will therefore be modified to reflect actual costs incurred via the retrospective mechanism.

6.123 Our determined allowances for rates in total for the 2014-2016 period are shown in the table below along with FE's requested allowances and the differences between the two amounts.

Table 48 – FE requested and determined rates allowances, £k

	2014	2015	2016
FE requested allowances	909	1,030	1,055
Final Determination	909	1,030	1,055
Variance	0	0	0

Source: FE and the Utility Regulator

Fees and Consulting

6.124 FE requested allowances under this heading which covered the costs of consultancy, legal and audit fees, as well as the licence fee. We have excluded the licence fee from the costs discussed in this section, and separately deal with the allowance for this in the following section.

6.125 The following table shows FE's historical actual costs compared to the PCR02 price control determination (excluding licence fees).

Table 49 – FE requested allowances and PCR02 determination for fees and consulting, £k

	2009	2010	2011	2012	2013
Final Determined Allowances (PCR02)	112	112	140	112	112
Actual Costs (2013 are best available)	235	132	85	290	143

Source: FE and the Utility Regulator

6.126 FE has requested £223k in 2014 and £123k per annum in 2015 and 2016 for fees and consulting. The requested allowances are broadly based on FE's costs for PCR02 with additional costs requested in 2014 as discussed further below.

6.127 We believe the consultancy and legal fees and recruitment costs are reasonable and therefore we have granted the allowances as requested. The audit fees request, on the other hand, represents a 100% increase on the previous allowance. FE has indicated that the additional fees are needed due to increasing customer numbers and revenue. We do not accept that the expected increase in turnover and customer numbers would result in such a significant change in audit costs and therefore we have not accepted the additional allowance. We have instead granted an allowance of £16.5k based on the average of the actual costs from 2009-2011.

6.128 In addition to the baseline costs, FE has requested £100k in 2014 for IME3 implementation, market opening and the safety case review. The majority of the work in relation to IME3 is complete and compliance with the new IME3 licence obligations was mandatory from December 2012. There may be some additional licence modifications relating to IME3, however these should be minor amendments. Therefore, we do not accept that FE requires an additional allowance for IME3 in 2014.

6.129 In relation to market opening, as FE already has a Distribution Network Code in place and the majority of market opening processes are now NI-wide, we do not envisage there being significant consultancy or legal costs required in relation to market opening going forward. In their response to the draft determination, FE argue that this additional expenditure is required in order to employ consultants to develop a Non Daily Metered (NDM) model for market opening. FE made no indication of this project until their consultation response. We have therefore granted no allowance for these requested costs. However, we understand that FE may require additional manpower for market opening and a specific allowance was made for this as discussed in the manpower section. Under the Other Capex cost line we have also granted an allowance of £10k per annum for network code and market opening and we have also ringfenced £100k in 2014 in relation to a switching system for ten towns market market opening.

6.130 Finally, we consider that FE's review of the safety case should be covered under the base level consultancy and legal fees. Safety should be reviewed on a continuous basis and therefore we are not granting any additional one-off allowances for the safety case review.

6.131 Our determined allowances for 2014 -2016 are shown in the table below along with FE's requested allowances and the variance. Note that the figures exclude licence fees

Table 50 – FE requested and determined allowances for fees and consulting, £k

	2014	2015	2016
FE requested allowances	223	123	123
Final Determination	110	110	110
Variance	-113	-13	-13

Source: FE and the Utility Regulator

Licence Fees

6.132 As we discussed in the PNGL context, licence fees are apportioned between the distribution licence holders according to their share of the total forecasted gas volumes conveyed in their respective areas for the year to which the fees relate. We treat licence fees as pass-through and therefore retrospectively adjust them to reflect the actual fees levied on FE by our office.

6.133 For the purposes of setting an *ex ante* allowance, we take the total cost to be apportioned to the two distribution licence holders, namely £162,715 per annum and use our determined volumes for each year of the price control to split the fee between FE and PNGL.

6.134 In general, FE is expected to convey about 30% of total forecasted NI volumes and therefore the determined licence fees for FE are in the order of £48k in each of the control period years which is a substantial reduction from FE's submission where they requested £280k per annum for licence fees.

Insurance

6.135 FE has requested allowances of £228k, £255k and £280k in 2014, 2015 and 2016 respectively. For comparison, the historical actual cost of insurance from 2009 to 2011 averaged £75k

6.136 FE has requested allowances for insurance costs that are considerably higher than both previous allowances and its actual costs. Since 2010, FE's actual insurance costs have exceeded the determined allowances. According to FE, this is due to increased network build with FE having been advised to increase its insurance liability cover in stages throughout the PCR02 period from approximately £5 million in 2009 to £80 million in 2012. We accept that FE's network has grown between 2009 and 2012; however, the increase in liability from £5 million to £80 million outweighs the increase in network build.

6.137 FE also stated that, following the unbundling of the BGE Group required by IME3, FE can no longer take advantage of the benefit of the overall insurance cover provided by the BGE Group, and since 2010 FE has been required to pay its insurance costs on a stand-alone basis.

6.138 FE has advised that its requested allowances for 2014-2016 are based on PCR02 actual costs and incorporate increases based on forecast customer numbers.

6.139 FE has provided additional information on the build up of its insurance costs. We accept that FE's historic actual costs may not provide a sound basis for granting allowances for business insurance for the GD14 period as FE can no longer benefit from savings through insurance provided by the BGE Group.

6.140 We have therefore decided to set allowances for FE's business insurance based on the benchmark of 1.04% of turnover used by Ofgem in the GDPCR price control. At the next price control, we will review the actual costs incurred during the GD14 period. The requested costs for car insurance and office insurance are reasonable and therefore we have granted the requested costs.

6.141 Our determined allowances for 2014 -2016 are shown in the table below along with FE's requested allowances and the difference between the two.

Table 51 – FE insurance costs, requested and allowed, £k

	2014	2015	2016
FE requested allowances	228	255	280
Final Determination	185	190	195
Variance	-43	-65	-84

Source: PNGL and Utility Regulator

6.142 It should be noted that the determined allowances shown in this table are higher than the final allowance shown in the FE opex summary table at the end of this section as we have assumed that an element of the insurance costs relates to office and car insurance and therefore we have apportioned an element of the insurance allowance to be recovered through the connections incentive.

Smaller Items

6.143 The residual FE cost lines shown below amount to approximately less than 4.2% of total claimed opex allowances:

~~Advertising, marketing and PR~~	~~Manpower~~	~~Network maintenance~~
Bank charges	~~Office costs (including IT)~~	**Training**
~~Fees and consulting~~	~~Parental recharges~~	**Travel and transport**
~~Insurance~~	**Professional subscriptions**	

6.144 For these cost lines, we adopt a collective approach similar to that for PNGL. To recap, we initially considered two main possibilities: (1) applying an average of the most recent actual spend over a desired number of years; or (2) using recent actual spend to determine a trend, and then using this trend to extrapolate forward.

6.145 We concluded that using a trend is less credible than using an average, since trending tends to exaggerate expenditure anomalies in any one particular year. Furthermore, we do not believe that these costs are rising in line with the expanding customer base.

6.146 We have therefore set allowances for these cost lines using an average, and for the purposes of our calculations we use the five-year timeframe of PCR02 (i.e. 2009 to 2013). Even though 2012-2013 are forecasts/budgeted spend, on the whole, we do not consider the observed trends to be unreasonable. The only exception is training where there is a significant increase between 2012 and 2013, which does not appear to be justified. We therefore adopt a 4-year average for training (i.e. excluding 2013).

6.147 Further information received indicated that there have been cost allocation issues with FE historically and within their submission in some of these areas, therefore, Professional subs, training and travel and transport were assessed for necessary recharges to the supply businesses driven by headcount. We have adjusted for this in deriving our final allowances.

6.148 The final allowances are shown in the following table.

Table 52 – Small items allowances for FE, £k

Cost Item	FE submission				Final Determination				Difference			
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total
Bank charges	9	9	9	**27**	4	4	4	**13**	-5	-5	-5	**-14**
Professional subs	12	12	12	**36**	5	5	4	**13**	-7	-7	-8	**-23**
Training	88	90	119	**297**	24	23	22	**70**	-64	-67	-97	**-227**
Travel and transport	229	239	242	**711**	108	105	100	**313**	-121	-134	-142	**-398**
Total	**338**	**351**	**382**	**1,071**	**141**	**137**	**131**	**409**	**-197**	**-214**	**-251**	**-662**

Source: FE and the Utility Regulator

6.149 We note that some of the allowances above are adjusted before setting the final overall opex allowances. This is because an element of these costs is allocated for recovery through the connections incentive mechanism, as we discussed above.

FE Supply Price Control

FE supply operating costs

6.150 FE is made up of a number of different businesses: Distribution, Ten Towns supply, Greater Belfast supply and Electricity supply. Due to the organisation of the business, the operational and managerial costs of all these businesses are inexorably linked, sharing premises, resources and systems in the daily operation of all businesses.

6.151 During the last FE price control we also set an allowance for supply operating costs. The purpose of setting an allowance for supply operating costs within the context of the distribution price control is to ensure that costs are allocated appropriately between supply and distribution businesses.

6.152 It is also appropriate to set supply costs in their own right to ensure supply costs are efficient and costs within supply are allocated appropriately between supply areas (Ten towns/Greater Belfast) and between activities (Gas/Electricity) and across all market sectors (<25,000 tpa, 25,000 to 75,000tpa, >75,000tpa) in line with licence requirements. Without this clarity FE could be incentivised to allocate costs from the competitive Belfast market into the Ten Towns market which does not open to competition until April 2015.

6.153 Finally, we will need to consider an established basis for costs which could be used in setting a maximum average supply tariff following market opening in April 2015. The FE supply licence grants FE a period of exclusivity for supplying gas to customers within the Ten Towns area. This period of exclusivity ended on 30

September 2012 for customers using more than 25,000 therms per annum. This meant that other supply companies could enter the market and compete with FE to supply gas to this section of the market. The period of exclusivity for all customers using less than 25,000 therms per annum will end on 31 March 2015. From 1 April 2015 the supply market in the Ten Towns area will be open to new entrants in all sectors. There will be a separate consultation in 2014 on applying a maximum average tariff, but the work undertaken through this process will determine supply costs for the Ten Towns supply area.

Approach

6.154 Supply operating costs are an important part of the distribution price control given the commonality of many of the cost areas between distribution and supply. Since the commencement of the previous price control, customer numbers for FE have increased steadily. The supply business itself has also changed with the supply of gas to customers in the Greater Belfast area and the supply of electricity. Therefore, for this price control we consider it prudent to carry out an in-depth analysis of the costs relating to the supply of gas in the Ten Towns area to ensure that costs are efficient, fair and transparent. We have sent information requests to FE requesting detailed information on costs and we are awaiting further information that is required in order to establish our position on appropriate allowances for the supply operating costs.

6.155 In the first quarter of 2014 we intend to publish our approach to market opening in the Ten Towns area including the application of a maximum average tariff in the Ten Towns area. Our approach to establishing an appropriate allowance for supply operating costs in the Ten Towns area is as follows:

- Conduct a bottom-up assessment of costs for major areas such as manpower, billing, IT systems, meter reading, etc. to establish if forecast costs are considered efficient.
- Compare costs with allowances in other areas of distribution to ensure consistency of treatment of costs across the control.
- Review costs allocated to other businesses in supply – Belfast area, electricity - to ensure that costs are fairly and reasonable allocated to separate businesses.
- Review the allocation of costs between sectors of the market (open/non open).
- Benchmark costs where appropriate against other supply companies in Northern Ireland and other jurisdictions.
- Establish a ‘minded to’ allowance for supply operating costs.
- Consult with stakeholders on this minded to position.

FE Opex Summary Pre-Efficiency

6.156 In the table below we set out a summary of the total pre-efficiency opex allowances we have determined for 2014, 2015 and 2016.

Table 53 – FE opex summary pre-efficiency, £k

Cost Item	FE revised submission				Final Determination				Difference				
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total	Total, %
Advertising, marketing and PR	1,555	1,505	1,405	**4,465**	76	76	76	**228**	-1,479	-1,429	-1,329	**-4,237**	-95%
Bank charges	9	9	9	**27**	4	4	4	**13**	-5	-5	-5	**-14**	-52%
Fees and consulting (incl. Licence Fees)	503	403	403	**1,309**	157	158	158	**473**	-346	-245	-245	**-836**	-64%
Insurance	227	255	280	**762**	184	190	195	**570**	-43	-65	-85	**-192**	-29%
Manpower	1,961	2,086	2,278	**6,325**	1,386	1,436	1,606	**4,428**	-575	-650	-672	**-1,897**	-30%
Office costs (incl. IT)	456	459	459	**1,374**	233	228	220	**681**	-223	-231	-239	**-693**	-50%
Parental recharges	1,010	931	952	**2,894**	487	487	487	**1,462**	-723	-645	-668	**-2,036**	-58%
Professional subscriptions	12	12	12	**36**	5	5	4	**14**	-7	-7	-8	**-22**	-62%
Rates	909	1,030	1,055	**2,993**	909	1,030	1,055	**2,993**	0	0	0	**0**	0%
Emergency costs + Network Maintenance	1,361	1,466	1,655	**4,483**	1,106	1,133	1,199	**3,438**	-255	-333	-456	**-1,045**	-23%
Training	88	90	119	**297**	21	20	19	**60**	-67	-70	-100	**-237**	-80%
Travel and transport	229	239	242	**711**	92	89	85	**267**	-137	-150	-156	**-444**	-62%
Total	**8,321**	**8,486**	**8,869**	**25,676**	**4,661**	**4,856**	**5,109**	**14,626**	**-3,660**	**-3,630**	**-3,760**	**-11,050**	**-43%**
Potential £ from connections incentive mechanism					710	710	710	2,130	710	710	710	2,130	n/a
Total	**8,321**	**8,486**	**8,869**	**25,676**	**5,371**	**5,566**	**5,819**	**16,756**	**-2,950**	**-2,920**	**-3,050**	**-8,920**	**-35%**

As per the comment under the summary table for smaller cost items, a number of cost lines in the table above may be lower than the allowance stated in the main body of this chapter. This is due to the apportionment of some of the allowed costs to the connections incentive mechanism.

Source: FE and the Utility Regulator

FE Opex Post-Efficiency

6.157 As detailed in chapter 14, we consider all opex other than licence fees and connection incentives to be controllable. The following table provides a breakdown of the total determined FE pre-efficiency opex allowances into controllable and uncontrollable opex.

Table 54 – FE controllable and uncontrollable opex, £k

FE Opex (£k)	2014	2015	2016	Total
Uncontrollable opex: connection incentive, licence fee	758	759	758	2,275
Controllable opex pre-efficiency	4,613	4,807	5,061	14,482
Total opex pre-efficiency	5,371	5,566	5,819	16,756

Source: FE and Utility Regulator

6.158 As detailed in chapter 14, we have applied the relevant compound Real Price Effect and ongoing productivity increase factors for each year to the controllable pre-efficiency opex allowance to establish the controllable post-efficiency opex allowance. We have then added the uncontrollable opex to obtain the overall post-efficiency opex allowance. The following table provides an overview over the results.

Table 55 – FE opex post-efficiency, £k

FE Opex (£k)	2014	2015	2016	Total
Controllable opex pre-efficiency	4,613	4,807	5,061	14,482
RPE and ongoing efficiencies	-45	-82	-125	-252
Controllable opex post-efficiency	4,568	4,725	4,936	14,230
Uncontrollable opex	758	759	758	2,275
Total opex post-efficiency	5,326	5,484	5,695	16,505

Source: FE and the Utility Regulator

7 CAPITAL EXPENDITURE, PNGL

Update from Draft Determination

7.1 For the draft determination, our review of capex performance used a high level or broad set of work activities of the type which are used by Ofgem for benchmarking the activities of the GB networks. Following the responses to the draft determination we reviewed this approach and identified that there are material differences in the nature of the work activities between PNGL and FE. Ignoring these differences would distort the performance assessment of the companies.

7.2 The main change therefore that we have made for the final determination has been to update the benchmarking assessment methodology to use narrower, more specific work activities. The final determined allowances for capex have now been set based on more specific pipe sizes for mains laying activities and more specific meter sizes for I&C services and I&C meter activities. Adopting this approach will result in an allowance that is more appropriate for the work activity actually constructed.

7.3 For the final determination we have also updated our approach to 4 bar and feeder mains as we consider that these allowances should be linked to an outcome. The purpose of the 4 bar and feeder is to pass properties. Therefore for the final determination we now treat the requested allowances in the same way as infill, where it is subject to an economic test and granted on the basis that it will pass properties.

7.4 In addition we have updated the assumptions used in the economic test to determine the allowance granted for mains.

7.5 Further detail on these changes is provided throughout the remainder of this section and in Appendix 4.

Introduction

7.6 PNGL has requested allowances excluding costs associated with implementation of the Traffic Management Act (TMA), of c£12.9 million, c£13.0 million and c£12.7 million in 2014, 2015 and 2016 respectively in its submission, to deliver a forecast workload as set out in the table below. For comparison historical actual costs from 2009 to 2011 have averaged around £12.2 million per annum, delivering an average workload which is also shown in the table.

Table 56 – Workloads: PNGL GD14 forecast and 2009 to 2011 average actuals

Workload	PNGL Submission			
	2014	2015	2016	Average 2009-11
Pipe laid, km	67	70	73	65
Properties passed	5,703	5,953	6,153	8,205
Connections (Domestic)	8,400	8,250	8,050	9,322
Connections (I&Cs)	378	378	378	446

Source: PNGL and the Utility Regulator

7.7 We commissioned our engineering consultants, Rune Associates Limited (Rune), to advise on the appropriateness of PNGL's allowance requests.

7.8 In undertaking this review, they examined the company's forward capital programme, some areas of which were considered in great detail, and questioned PNGL staff on the build-up of the cost estimates. We have taken on board Rune's findings in setting our allowances for capex.

Overview

General overview

7.9 PNGL's submission for forecast capex costs generally consisted of a forecast workload multiplied by an estimated unit rate. PNGL has not included any assumptions in their submission regarding changes to unit rates.

7.10 In analysing the allowance requests, we sought to make comparisons, where possible with suitable comparators, however, in most cases, PNGL's split between the categories of work and expenditure differed from FE's split and the splits used by GB GDNs.

7.11 Therefore to facilitate comparisons where the split between the categories of work and expenditure differed, we adopted an analysis technique which combined the areas of expenditure into a "basket of work". The "basket of work" was then analysed and compared against benchmark values applied to the volume of each work category. This technique builds upon principles which have been used by Ofgem in analysis for both GDPRC1 and RIIO-GD1 price controls. Further detail on this process is given in Appendix 4.

7.12 For the draft determination, the review was carried out using a high level or broad set of work activities of the type which are used by Ofgem for their connections benchmarking of the GB networks for new gas connections activities. Following comments received in response to the draft determination we reviewed this approach to identify if it would be more appropriate to use narrower, more specific work activities.

7.13 The review concluded that there are material differences in the nature of the work activities between PNGL and FE, which, if not considered would distort the performance assessment of the companies. It was therefore concluded that the benchmarking assessment methodology would switch to using more specific work activities.

7.14 By moving to this more specific categorisation of work types, the benchmarking assessment has given a much closer fit between the benchmarking assessments made and costs actually incurred in carrying out the work.

7.15 The following table shows the allowances requested by PNGL in their submission for each high level category of work. In the table, the costs under "PNGL Restated Submission" display the effect of rescaling the costs of items within the basket of work so that they are comparable to other distribution networks.

7.16 Moving to a more detailed level of activity breakdown has not affected the overall scale of costs but has still resulted in some redistribution of costs between the categories of work. The restated costs and implied unit rates at the more specific activity level were used in the comparative analysis. Further detail on the methodology used to determine allowances is also provided in Appendix 4.

Table 57 – Restatement of PNGL submission for 'basket of work' items

	PNGL Submission £k			PNGL Restated Submission £k		
	2014	2015	2016	2014	2015	2016
New build housing mains	1,505	1,656	1,780	1,462	1,635	1,775
Other mains	2,358	2,354	2,358	2,967	3,010	3,045
Domestic services	4,762	4,686	4,567	5,216	5,063	4,882
Domestic meters	2,510	2,487	2,441	1,924	1,902	1,865
I&C Services	783	789	792	385	388	390
I&C meters	533	537	540	496	511	521
Totals	**12,450**	**12,509**	**12,477**	**12,450**	**12,509**	**12,477**

Source: PNGL and Rune Associates

7.17 Their methodology allowed us to prepare capital allowances at total level and for each cost item. The total capex allowance is consistent with the comparative efficiency analysis but, some of the allowances at cost item level may appear to offer allowances that are greater than those requested, or that are significantly lower. This occurs as a result of the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar.

7.18 We considered issues which could potentially affect comparability between PNGL and FE but concluded that there is no material impact on the analysis process and in our opinion no issues warrant PNGL or FE being granted higher allowances than the other.

7.19 All unit rates are shown in £, implied unit rates from the PNGL submission used in tables are shown in italics and are shown to the nearest £. The determined unit rates as part of the allowances are not in italics and are rounded to whole £s. All costs are expressed in £k and rounded to the nearest £k. All pipe lengths are shown in km and rounded to one decimal place.

7.20 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

Street works legislation

7.21 In GB there are two main pieces of legislation which set out the rules and regulations that apply whenever utilities or any other such organisations undertake capital works on public roads. They are the Traffic Management Act (TMA) and the New Roads and Street Works Act (NRSWA). Equivalent legislation has not yet been implemented in Northern Ireland, but it is anticipated that the Department for Regional Development (DRD) will proceed with implementation in due course.

7.22 There is uncertainty in terms of the timing of implementation of the TMA legislation, and the effect on operating costs. To address these issues PNGL has included an estimated uplift of ten per cent to those capex cost items that will be impacted. In recognition of the uncertainty we have agreed with PNGL that all costs associated with the legislation will be adjusted retrospectively at the time of the next price control, to reflect the actual level of expenditure incurred as a result. This approach protects both PNGL (in the event actual costs turn out higher) and consumers (in the more likely event that implementation is delayed, or that the impact is less than our assumption).

7.23 PNGL has embedded the ten per cent uplift into the unit rates for the following cost items (since these activities involve capital works on public roads):

- Mains;
- Domestic services; and
- I&C services.

7.24 In order to show a consistent assumption for likely TMA costs, we have included our assessment of a reasonable estimate of TMA costs which will be subject to the retrospective adjustment at the time of the next price control. These estimates are based upon 10% of the capex allowance excluding PRS, Meter and "other" capex costs.

Management fee

7.25 PNGL outsource much of its capital works to a third party contractor, currently McNicholas Construction Limited (McNicholas). Costs forecast under the generic heading of “management fee” covers all costs incurred by McNicholas associated with managing PNGL construction activity i.e. manpower and associated costs, supply chain costs, depot costs, security, training, safety equipment, general office and support costs etc.

7.26 In addition, the management fee also covers operating costs relating to staff directly employed by PNGL, plus their associated overheads, that are recharged from opex to capex.

7.27 PNGL submitted their allowance request with the management fee as a separate item; however we asked PNGL to subsequently allocate the management fee element within each of the capex activities.

7 Bar Mains

7.28 PNGL does not plan to lay any 7 bar pipe during the control period. Accordingly we have not needed to assess or grant an allowance for this cost item.

Infill Mains – New Build Domestic

7.29 We are of the opinion that the cost of installing infill mains to new build housing is characteristically different to installing other types of main.

7.30 The comparative efficiency analysis has been carried out at individual pipe size level and the detailed results, including allowed unit cost for each pipe size, are set out in Table 8 within Appendix 4.

7.31 PNGL has requested an infill allowances for new build based on 11 metres per property passed which is significantly higher than the 2009-11 average of 5.9 metres. PNGL has explained this on the basis that future new build is more likely to focus on houses compared to apartments. While the ratio of houses and apartments may fluctuate over time we do not see why the Greater Belfast market would change so radically so quickly. We have also not seen any evidence linking historic fluctuations in new build houses and apartments with historic fluctuations in average metres per new build property passed.

7.32 We have based our approach for new build domestic housing upon the average historical level of metres per property passed during 2009 to 2011 which is 5.9 metres. This results in the determined allowances shown in the table below

Adjusting for Actuals

7.33 We will apply the retrospective mechanism to adjust for the actual number of properties passed. However it is important to note that in addition, to ensure that PNGL do not have inappropriate incentives to outperform by simply choosing projects with less metres per property passed we are including a retrospective adjustment to the annual average number of metres of gas mains laid per property passed up to a cap of 5.9 metres.

7.34 This mechanism is part of the retrospective mechanism and will be updated for actual outturns of properties passed and number of metres of gas mains. This mechanism ensures PNGL will receive no benefit from cherry picking certain projects.

Table 58 – Infill mains allowance for new build housing, PNGL

New Build Housing Mains	PNGL Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
New Build Pipe laid, km	25.2	28.1	30.3	25.2	28.1	30.3	13.6	15.0	16.2
New Build Average Cost per metre, £	*60*	*59*	*59*	*58*	*58*	*59*	*56*	*56*	*56*
Properties Passed	2,300	2,550	2,750	2,300	2,550	2,750			
Properties Passed Target							2,300	2,550	2,750
Total, £k	1,505	1,656	1,780	1,462	1,635	1,775	760	842	908

Source: PNGL and the Utility Regulator

4 Bar & Feeder Mains

7.35 In the draft determination we highlighted that we needed to discuss with PNGL how any allowances for 4 bar and feeder would need to be linked to an identifiable outcome. Since then PNGL has confirmed that the ultimate purpose of its request for 4 bar and feeder is to pass properties.

7.36 Therefore we have removed this allowance and consider this it will be incorporated into the other mains section below. The purpose of the other mains section is to provide PNGL with an allowance to pass properties.

Other Mains - Existing Housing Domestic and I&C

7.37 We are of the opinion that, on an equivalent pipe size basis there is no material difference between the cost of installing 4 bar mains, low pressure feeder mains and infill mains to existing housing. Our analysis has concluded that these types of main should be analysed as a single category of work.

7.38 The comparative efficiency analysis has been carried out at individual pipe size level and the detailed results, including allowed unit cost for each pipe size, are set out in Table 9 within Appendix 4.

Background

7.39 We have merged the previous categories of infill mains (Owner Occupied, NIHE and I&C) and 4 bar and feeder mains into a single definition of gas mains to supply existing domestic housing and I&C.

7.40 In the PC03 price control we allowed PNGL an infill allowance based on the cost per metre of infill, the number of metres of infill required to pass a property and the number of properties passed. We had allowed the number of properties passed to be retrospectively adjusted although the cost per metre and number of metres of infill per property passed was fixed.

7.41 In the PNGL12 price control, we granted PNGL infill allowances which were calculated using the number of metres required to pass a property and the cost per metre. Varying infill allowances were set dependent on the type of property passed (i.e. Owner Occupied, NIHE, New Build or I&C). We allowed the number of properties passed to be retrospectively adjusted but the allowance per property was fixed.

7.42 As part of its GD14 submission PNGL set out a list of infill projects which still remained within its licence area. PNGL has completed desktop designs for just over half of these remaining properties, and they have informed us that there are over 9,000 properties which have not yet been designed.

7.43 PNGL raised the question of what constitutes an economic project and therefore we carried out some initial analysis on this in order to determine the number of properties passed for 2014 – 2016.

Economics of Gas Mains

7.44 The main principle we have used in carrying out an economic test is that gas mains should only be laid where there is a reasonable prospect that the initial cost outlay will be paid back over the useful economic period that a typical customer will connect and burn gas.

7.45 This principle ensures that the overall cost of gas to all consumers is appropriate. If projects were to be allowed where associated revenues did not cover costs, the price for everyone would increase and this increase could become very significant. This is also consistent with our approach to network extensions outside licence areas.

7.46 We set out in the draft determination an initial economic analysis to determine the quantity of mains that would be allowed. This considered the costs and revenues associated with laying mains to pass properties and concluded that an economic cost per property passed would be £507 and using a cost per metre for infill of £70, we have determined an allowance of 7.2 metres of infill per property passed.

7.47 In response to the draft determination we received a number of comments on the assumptions within our economic analysis and have also updated it for determined costs. Thus our final economic analysis, which considers an average mains project passing 1,000 properties makes the following assumptions:

- 95% of properties are existing domestic housing and 5% are small industrial and commercial properties
- A typical level of gas burn is assumed in therms per annum, to understand the revenue that is available from when a customer is connected.

- Appropriate service and meters costs of connecting a customer from the main gas network into the property including meter replacement after 20 years;
- Not all customers will connect in year 1 when gas is available, so a phased connection assumption is used, to reflect a typical connection profile.
- A 40 year payback method has been selected to assume the total revenue, based on a certain number of connections
- The Incentive cost is the allowance to cover the connections incentive.
- An amount has been included for opex costs.

Table 59 – Assumptions for gas mains analysis, PNGL

Assumptions for Mains Analysis - GD14	*Customer Type*	
Customer Type	*OO Dom*	*SIC*
Properties Passed 1,000 (Split at OO - 95%/SIC - 5%)	950	50
Average Consumption (tpa)	410	2,000
Conveyance Tariff (ppt)	40	36
Service Cost (£)	666	1,042
Meter Cost (£)	217	559
Incentive Cost (£)	540	0
Payback Period (yrs)	40	40
* Connection Rates for Domestic Properties Passed 2014 - 5%, 2015 - 2%, 2016 - 0% and 35%		
** Connection Rates for SIC Properties Passed 2014 - 18%, 2015 - 5%, 2016 - 2% and 61%		
*** Rate of Return of 7.5% to 2016 and 4.83% post 2016		

Source: The Utility Regulator

7.48 The result of our economic analysis, based on the assumptions, is that an average allowance of £515 per property passed would be economic. Using a cost per metre for gas mains of £67, we have therefore determined an allowance of 7.7 metres of gas mains per property passed.

7.49 Given the increased allowance in metres per property passed we have reviewed the dataset of properties which PNGL has not yet passed and we are now targeting PNGL to pass 3,403 properties per annum. This includes Owner Occupied, NIHE and I&C properties. This now matches PNGL's forecast of 3,403 properties per annum and will allow more customers to enjoy the benefits of gas.

Adjusting for Actuals

7.50 We are mindful that the length of gas mains required to connect a property can vary.

7.51 We will continue to apply the retrospective mechanism to adjust for the actual number of properties passed. However it is important to note that in addition, to ensure that PNGL do not have inappropriate incentives to outperform by simply choosing projects with less metres per property passed we are including a retrospective adjustment to the annual average number of metres of gas mains laid per property passed up to a cap of 7.7 metres.

7.52 This mechanism is part of the retrospective mechanism and will be updated for actual outturns of properties passed and number of metres of gas mains. This mechanism ensures PNGL will receive no benefit from cherry picking certain projects.

7.53 In addition to this we are continuing with the introduction of a mechanism to ensure PNGL are adequately incentivised to continue to extend the network as proposed in the draft determination. In theory PNGL could fail to build a single metre of gas mains and not suffer any negative consequences although we accept there is a general incentive to grow the industry. Therefore we determine that failure to achieve the targeted number of properties passed will result in a penalty of £50 for every property below the target, and passing a larger number of properties than the target will result in a reward of £20 per additional property over the target[36]. This will also form part of the retrospective mechanism.

7.54 We note the responses to the draft determination that this is asymmetric but given that PNGL has strong control over what properties it passes the penalty is not onerous.

7.55 The following table summarises the total PNGL submission for Other Mains, the restatement of the implied unit rates used in the comparative efficiency analysis and our determined allowance and includes the properties passed target for gas mains associated with existing domestic housing and I&C properties.

7.56 As indicated in the PNGL/FE Performance Comparison section in Appendix 4, although the total recommended Capex allowance is consistent with the comparative efficiency analysis, due to inconsistent cost allocation by companies and an assumption that the unit costs of both of the NI companies should be similar, some of the recommendations at cost item level offer allowances that are greater than those requested or that are significantly lower. In the particular case of Other Mains to existing domestic housing and I&C properties, the cost per metre allowance is greater than the PNGL submission.

Table 60 – Other mains –Existing housing domestic and I&C allowance, PNGL

Other Mains	PNGL Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Pipe laid, km	42.0	42.4	42.6	42.0	42.4	42.6	26.2	26.2	26.2
Average Cost per metre, £	*56*	*56*	*55*	*71*	*71*	*71*	*68*	*68*	*68*
Properties Passed	3,403	3,403	3,403	3,403	3,403	3,403			
Properties Passed Target							3,403	3,403	3,403
Total, £k	2,358	2,354	2,358	2,967	3,010	3,045	1,788	1,788	1,788

Source: PNGL and the Utility Regulator

Pressure Reduction Stations

7.57 Our Consultants have reviewed the forecast activity volumes and costs associated with the construction of PRS installations, which are minimal. The levels are consistent with the historical actual performance and the intent to continue extending

[36] For the avoidance of doubt and by way of examples, if PNGL pass an additional 500 properties above annual target, then the allowance will be adjusted upwards by £10k in that year, however, if PNGL pass 500 properties less than annual target, then the allowance will be adjusted downwards by £25k in that year.

the opportunity for connection of properties to the network. We have therefore granted allowances as detailed in the table below.

Table 61 – Pressure reduction station allowances, PNGL

Variable	PNGL Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
New PRS IP:(MP/LP)	1	1	0	1	1	0
New PRS MP:LP	1	1	0	1	1	0
Cost, £k	**156**	**155**	**0**	**156**	**155**	**0**

Source: PNGL and the Utility Regulator

Domestic Services

7.58 PNGL plans to connect 8,400, 8,250 and 8,050 domestic customers in 2014, 2015 and 2016 respectively. We have applied an upwards adjustment to the forecast for domestic owner occupiers of 1400, 1800 and 2200 for 2014, 2015 and 2016 respectively.

7.59 In its submission, the average cost per service to existing housing was £690 and to new build was £294 although when restated as part of the comparative efficiency analysis, the rates were £707 and £393 respectively. The outcome of our performance comparison analysis is an allowance of £680 per service to existing housing and £378 to new build housing.

Table 62 – Domestic services allowance, PNGL

Variable	PNGL Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Existing housing	6,100	5,700	5,300	7,500	7,500	7,500
Cost per service existing, £	*673*	*691*	*706*			
New build housing	2,300	2,550	2,750	2,300	2,550	2,750
Cost per service new build, £	*286*	*294*	*301*			
Total, £k	**4,762**	**4,686**	**4,567**			
	Restated Submission			Final Determination		
Cost per service existing, £	*707*	*711*	*715*	680	680	680
Cost per service new build, £	*393*	*395*	*397*	378	378	378
Total, £k	**5,216**	**5,063**	**4,882**	**5,969**	**6,064**	**6,140**

Source: PNGL and the Utility Regulator

Domestic Meters

7.60 A meter will be required for all new connections. PNGL also included in their submission, costs for replacement meters in 2014, 2015 and 2016 without any indication of the numbers they intended to replace. In the draft determination, we used the difference in unit rates for new and replacement meters provided by PNGL for 2017, to calculate unit rates and number of replacement meters for 2014 – 2016. We estimated that 266 replacement meters per year would be required for the submitted costs.

7.61 PNGL has clarified that no replacement meters are required during the GD14 period (i.e. meters needing replaced as they have reached the end of their normal operating life). PNGL noted that the submitted costs in relation to meter replacements was a transposition error but added that these costs are required in relation to meter failures. PNGL asked that an allowance of 1.38% of domestic connections would be granted in line with the approach taken in PNGL12. We asked PNGL to provide information on the actual numbers and costs of meter failures in previous years. PNGL were unable to provide this information and therefore we have determined that no allowance will be granted for this cost area.

7.62 Our recommended allowance for a new meter is lower than that requested by PNGL as we believe the cost split between meters and services has not previously been on a consistent basis.

7.63 This allowance has been applied to the higher assumed level of connections, as for domestic services. The determined allowances for domestic meters are shown in the following table.

Table 63 – Domestic meters allowance, PNGL

Variable	PNGL Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Number of new meters	8,400	8,250	8,050	9,800	10,050	10,250
Cost per new meter, £	*299*	*301*	*303*			
Number of replacement meters	0	0	0	0	0	0
Cost/replacement meter, £						
Total, £k	2,510	2,487	2,441			
	Restated Submission			Final Determination		
Cost per new meter, £	*229*	*231*	*232*	220	220	220
Cost/replacement meter, £				220	220	220
Total, £k	1,924	1,902	1,865	2,156	2,211	2,255

Source: PNGL and the Utility Regulator

I&C Services

7.64 PNGL plans to connect 378 I&C customers in each year of the GD14 period. In its submission, which referenced small and large I&C loads, the cost per service averaged £2,084. The comparative efficiency analysis has been carried out based on the following size categories:

- Very Small (U6)
- Small (U16-U40)
- Medium (U65-U160)
- Large (U250-U2500)

7.65 Our average allowance for each year of the period is £980 per service and the detailed results, including allowed unit cost for each load size, are set out in Table 10 within Appendix 4.

7.66 As indicated previously, although the total recommended capex allowance is consistent with the comparative efficiency analysis, due to the restatement of costs to enable comparison between the companies and the assumption that the unit costs of both of the NI companies should be similar, some of the recommendations at cost item level offer allowances that are greater than those requested or that are significantly lower. In the particular case of I&C Services, our allowance is significantly less than the PNGL submission.

Table 64 – I&C services allowance, PNGL

Variable	PNGL Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Number of connections	378	378	378	378	378	378
Average Cost per service, £	*2,070*	*2,086*	*2,094*			
Total, £k	783	789	792			
	Restated Submission			Final Determination		
Average Cost per service, £	*1,019*	*1,025*	*1,030*	980	980	980
Total, £k	385	388	390	370	370	370

Source: PNGL and the Utility Regulator

I&C Meters

7.67 A meter will be required for all new I&C connections, and PNGL estimates that this will amount to 378 new meters per year. In addition PNGL suggests that around 149 existing meters will need replacing each year. PNGL's submission identified the average cost per new meter as £563 and per replacement meter as £2,178.

7.68 The comparative efficiency analysis for new and replacement meters has been carried out based on a range of meter sizes from U6 through to U2500. As meter costs are dependent on load size, the unit costs over such a wide range could be expected to vary significantly.

7.69 Our allowance averages £518 for new meters and £2,119 for replacement meters, the detailed results, including allowed unit cost for each load size, are set out in Table 11 within Appendix 4.

Table 65 – I&C meters allowance, PNGL

PNGL I&C Meter Summary	PNGL Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Number of new meters	378	378	378	378	378	378	378	378	378
Average Cost per new meter, £	*559*	*563*	*565*	*539*	*542*	*545*	*518*	*518*	*518*
Total, £k	***211***	***213***	***214***	***204***	***205***	***206***	***196***	***196***	***196***
Number of replacement meters	145	149	153	145	149	153	*96*	*217*	*144*
Average Cost per replacement meter, £	*2,216*	*2,180*	*2,138*	*2,018*	*2,058*	*2,061*	*3,007*	*1,673*	*1,677*
Total, £k	***322***	***324***	***326***	***293***	***306***	***315***	***289***	***363***	***241***
Total, £k	533	537	540	496	511	521	485	559	437

Source: PNGL and the Utility Regulator

Other Capex Items

7.70 The individual cost items under “other capex” are: network code, fixtures and fittings, leasehold improvements, capex-related IT and management fee. The management fee has already been allocated across the activity costs.

7.71 Fixtures and fittings is a relatively small item and we have granted the requested allowance. In the case of capex-related IT and in the absence of any detailed justification for an increase above 2011 levels, we have granted an allowance of £65k per annum.

7.72 The PNGL submission did not provide any justification for network code and leasehold improvements. In the draft determination we therefore made no allowance for these items. In their response to the draft determination, PNGL did not provide any additional information on these costs.

7.73 For the final determination we continue to disallow the costs relating to leasehold improvements. We have however granted an allowance of £10k per annum under the network code cost line. We wish to be clear that we expect PNGL to work with FE and also with gas supply companies in order to facilitate and improve competition and the allowances granted under the network code cost line should be utilised to assist in this objective. Should any other significant code modifications require an allowance, we will consider business cases put forward.

7.74 This provides a total allowance of £100k per annum for Other Capex Items.

Traffic Management Act

7.75 As stated previously, in our analysis we have used cost and unit rates that do not include TMA. PNGL’s TMA forecasts have been retained as a separate cost line in the Capex summary table, which will better facilitate the retrospective adjustment at the time of the next price control.

PNGL Capex Summary Pre-Efficiency

7.76 In the following table we set out a summary of the total pre-efficiency capex allowances we have determined for 2014, 2015 and 2016. Note that these allowances are based on PNGL achieving an additional 1400, 1800 and 2200 domestic owner occupied connections in 2014, 2015 and 2016 respectively, however they also reflect the reduced level of mains that has been determined for the GD14 period..

Table 66 – Capex summary with additional connections workload, £k

Cost Item £k	PNGL Submission				Final Determination				Difference				
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total	Total, %
7 bar mains	0	0	0	0	0	0	0	0	0	0	0	0	n/a
New build housing mains	1,505	1,656	1,780	4,941	760	842	908	2,510	-746	-814	-871	-2,431	-49%
Other mains	2,358	2,354	2,358	7,069	1,788	1,788	1,788	5,363	-570	-566	-570	-1,706	-24%
Pressure reduction stations	156	155	0	311	156	155	0	311	0	0	0	0	n/a
Domestic services	4,762	4,686	4,567	14,015	5,969	6,064	6,140	18,173	1,208	1,378	1,572	4,158	30%
Domestic meters	2,510	2,487	2,441	7,438	2,156	2,211	2,255	6,622	-354	-276	-186	-816	-11%
I&C services	783	789	792	2,363	370	370	370	1,111	-412	-418	-421	-1,251	-53%
I&C meters	533	537	540	1,610	485	559	437	1,481	-48	21	-103	-129	-8%
Network code	75	75	75	225	10	10	10	30	-65	-65	-65	-195	-87%
Fixtures and fittings	25	25	25	75	25	25	25	75	0	0	0	0	n/a
Leasehold improvements	48	46	0	94	0	0	0	0	-48	-46	0	-94	-100%
IT	150	150	150	450	65	65	65	195	-85	-85	-85	-255	-57%
Total excluding TMA	12,904	12,960	12,727	38,591	11,784	12,089	11,998	35,871	-1,120	-871	-729	-2,720	-7%
Traffic Management Act	738	743	743	2,224	889	906	921	2,716	151	164	177	492	22%
Total including TMA	13,642	13,703	13,471	40,815	12,672	12,996	12,919	38,587	-969	-707	-552	-2,228	-5%
Pipe laid (km)	67.3	70.4	73.0	211	39.8	41.2	42.4	123	-27	-29	-31	-87	-41%
Connections (Domestic)	8,400	8,250	8,050	24,700	9,800	10,050	10,250	30,100	1,400	1,800	2,200	5,400	22%
Connections (I&Cs)	378	378	378	1,134	378	378	378	1,134	0	0	0	0	n/a

Source: PNGL and the Utility Regulator

PNGL Capex Post-Efficiency

7.77 As detailed in chapter 14, we consider all capex including TMA to be controllable.

7.78 As detailed in chapter 14, we have applied the relevant compound Real Price Effect and ongoing productivity increase factors for each year to the controllable pre-efficiency capex allowance to establish the controllable post-efficiency capex allowance. This equals the overall post-efficiency capex allowance as the uncontrollable capex is £0 for each year of the price control period. Table 67 provides an overview over the results.

Table 67 – PNGL capex post-efficiency, £k

PNGL Capex (£k)	2014	2015	2016	Total
Controllable capex pre-efficiency	12,672	12,996	12,919	38,587
RPE and ongoing efficiencies	-566	-658	-742	-1,966
Controllable capex post-efficiency	12,106	12,338	12,177	36,621
Uncontrollable capex	0	0	0	0
Total capex post-efficiency	12,106	12,338	12,177	36,621

Source: PNGL and the Utility Regulator

8 CAPITAL EXPENDITURE, FE

Update from Draft Determination

8.1 For the draft determination, our review of capex performance used a high level or broad set of work activities of the type which are used by Ofgem for benchmarking the activities of the GB networks. Following the responses to the draft determination we reviewed this approach and identified that there are material differences in the nature of the work activities between PNGL and FE. Ignoring these differences would distort the performance assessment of the companies.

8.2 The main change therefore that we have made for the final determination has been to update the benchmarking assessment methodology to use narrower, more specific work activities. The final determined allowances for capex have now been set based on more specific pipe sizes for mains laying activities and more specific meter sizes for I&C services and I&C meter activities. Adopting this approach will result in an allowance that is more appropriate for the work activity actually constructed.

8.3 For the final determination we have also updated our approach to all mains allowances, which includes 4 bar mains, feeder mains, infill mains and security of supply projects. FE do not have appropriate reporting processes in place in order for them to provide the detail required to carry out an economic test on the mains cost. We have therefore decided to allow FE the quantity of mains requested. However the costs of all mains will be ring fenced and the actual quantity allowed will be determined when FE provides the required data in an appropriate format as advised, within no later than 9 months of the commencement of this price control.

8.4 Further detail on these changes is provided throughout the remainder of this section and in Appendix 4

Introduction

8.5 FE has requested an allowance excluding costs associated with implementation of the Traffic Management Act (TMA), of c£13.9 million, c£11.9 million and c£10.3 million in 2014, 2015 and 2016 respectively in its submission, to deliver a forecast workload as set out in the table below. For comparison historical actual costs from 2009 to 2011 have averaged around £10.4 million per annum, delivering an average workload which is also shown in the table.

Table 68 – Workloads: FE GD14 forecast and 2009 to 2011 average actuals

Workload	FE Submission			
	2014	2015	2016	Average 2009-11
Pipe laid, km	87	71	63	93
Connections (Domestic)	4,000	4,000	3,800	2,371
Connections (I&Cs)	152	102	52	275

Source: PNGL and the Utility Regulator

8.6 We commissioned our engineering consultants, Rune Associates Limited, to advise on the appropriateness of FE's allowance request.

8.7 In undertaking this review, they examined the company's forward capital programme, some areas of which were considered in great detail, and questioned FE staff on the build-up of the cost estimates. We have taken on board Rune's findings in setting our allowances for capex.

Overview

General overview

8.8 FE has chosen to include an uplift of 15% on unit rates for the GD14 period. This has been removed for the purpose of the analysis.

8.9 In analysing the allowance requests, we sought to make comparisons, where possible with suitable comparators, however, in most cases, FE's split between the categories of work and expenditure differed from PNGL's split and the splits used by GB GDNs.

8.10 Therefore to facilitate comparisons where the split between the categories of work and expenditure differed, we adopted an analysis technique which combined the areas of expenditure into a "basket of work". The "basket of work" was then analysed and compared against benchmark values applied to the volume of each work category. This technique builds upon principles which have been used by Ofgem in analysis for both GDPRC1 and RIIO-GD1 price controls. Further detail on this process is given in Appendix 4.

8.11 For the draft determination, we carried out our review using a high level or broad set of work activities of the type which are used by Ofgem for their connections benchmarking of the GB networks for new gas connections activities. Following comments received on the draft determination we reviewed this approach to review if it would be more appropriate to use narrower, more specific work activities.

8.12 Their review concluded that there are material differences in the nature of the work activities between the two companies which if not considered would distort the performance assessment of the companies. It was therefore concluded that the benchmarking assessment methodology would switch to using more specific work activities.

8.13 By moving to this more specific categorisation of the different work type undertaken the benchmarking assessment has given a much closer fit to the assessments made and costs actually incurred in carrying out the work.

8.14 The following table shows the allowances requested by FE in their submission for each high level category of work. In the table, the costs under "FE Restated Submission" display the effect of rescaling the costs of items within the basket of work so that they are comparable to other distribution networks.

8.15 Moving to a more detailed level of activity breakdown has not affected the overall scale of costs but has still resulted in some redistribution of costs between the categories of work. The restated costs and implied unit rates at the more specific activity level were used in the comparative analysis. Further detail on the methodology used to determine allowances is also provided in Appendix 4.

Table 69 – Restatement of FE submission for 'basket of work' items

	FE Submission £k			FE Restated Submission £k		
	2014	2015	2016	2014	2015	2016
New build housing mains	655	665	659	1,084	1,080	1,051
Other mains	7,274	5,533	4,771	7,446	5,633	4,791
Domestic services	3,736	3,790	3,566	3,306	3,293	3,031
Domestic meters	793	805	755	1,176	1,171	1,084
I&C Services	674	462	238	218	147	74
I&C meters	215	151	84	118	80	42
Totals	13,348	11,405	10,073	13,348	11,405	10,073

Source: FE and Rune Associates

8.16 This methodology allowed us to prepare capital allowances at total level and for each cost item. The total capex allowance is consistent with the comparative efficiency analysis but, some of the allowances at cost item level may appear to offer allowances that are greater than those requested, or that are significantly lower. This occurs as a result of the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar.

8.17 We have considered issues which could potentially affect comparability between FE and PNGL but concluded that there is no material impact on the analysis process and in our opinion no issues warrant FE or PNGL being granted higher allowances than the other.

8.18 All unit rates are shown in £, implied unit rates from the FE submission used in tables are shown in italics and are shown to the nearest £, determined unit rates as part of the allowances are not in italics and are rounded to whole £s. All costs are expressed in £k and rounded to the nearest £k. All pipe lengths are shown in km and rounded to one decimal place.

8.19 All allowances referred to in this document are pre-efficiency unless explicitly stated otherwise.

Street works legislation

8.20 In GB there are two main pieces of legislation which set out the rules and regulations that apply whenever utilities or any other such organisations undertake capital works on public roads. They are the Traffic Management Act (TMA) and the New Roads and Street Works Act (NRSWA). Equivalent legislation has not yet been implemented in Northern Ireland, but it is anticipated that the Department for Regional Development (DRD) will proceed with implementation in due course.

8.21 There is uncertainty in terms of the timing of implementation of the TMA legislation, and the effect on operating costs. To address these issues FE has included an estimated uplift of ten per cent to those capex cost items that will be impacted. In recognition of the uncertainty we have agreed with FE that all costs associated with the legislation will be adjusted retrospectively at the time of the next price control, to reflect the actual level of expenditure incurred as a result. This approach protects both FE (in the event actual costs turn out higher) and consumers (in the more likely event that implementation is delayed, or that the impact is less than our assumption).

8.22 FE has embedded the 10% uplift into the unit rates for the following cost items (since these activities involve capital works on public roads):

- Mains;
- Domestic services; and
- I&C services.

8.23 At our Consultant’s request, FE has confirmed the amount associated with TMA which should be separated out from their submission. The review of capex costs and benchmarking carried out to set allowances was based on cost and unit rates that do not include estimates for TMA.

8.24 In order to show a consistent assumption for likely TMA costs, we have included our assessment of a reasonable estimate of TMA costs which will be subject to the retrospective adjustment at the time of the next price control. These estimates are based upon 10% of the capex allowance excluding PRS, Meter and "other" capex costs.

7 Bar Mains

8.25 FE does not plan to lay any 7 bar pipe during the control period. Accordingly we have not needed to assess or grant an allowance for this cost item.

All Mains

8.26 We set out in our draft determination that we require the GDNs to make clear the outputs that will be delivered by allowances. FE has set out three reasons that mains will be required. These are (i) pass properties, (ii) large projects e.g. to large I&C and (iii) security of supply. We have treated previous large projects on a standalone basis and we plan to continue with this as set out in the uncertainty mechanism in section 15.

8.27 In order to provide an allowance for passing properties we require an economic assessment to be made to ensure that the costs of mains are matched by the revenues from future connections off those mains. This economic analysis requires assumptions based on historic number of property passed, type of property passed i.e. NIHE, OO, IC or new build and annual connection rates for those properties passed. It also requires a detailed assessment of the licence area to understand the amount and types of properties that remain to be passed.

8.28 We noted in the draft determination that FE did not have the recording processes in place to provide some of this information. In the draft determination we used the same average metre per property passed for FE as we did for PNGL.

8.29 We would accept that the quantity which would apply to FE may be very different from PNGL. We had hoped to be able to incorporate robust data in the final determination to determine an economic quantity of infill required by FE. This is currently not available and therefore we do not have high confidence in setting the quantity of infill for FE.

8.30 We have decided that we will allow FE the quantity of mains they requested in order to pass properties. FE has assured us that they believe this is all economic. However this quantity will be ring fenced and the actual quantity FE will be allowed will be determined when FE provides the robust data required to make this determination.

8.31 As with the approach determined for PNGL, we will apply a retrospective mechanism to adjust for the actual number of properties passed. We will also include a retrospective adjustment to the average number of metres of mains laid per property passed up to a cap which will be determined once we receive the data from FE.

8.32 Similarly we have included mains quantities which FE states are linked to security of supply projects. We have not received detailed analysis to justify these projects and they are ring fenced and we will only give formal approval after robust justification has been provided.

8.33 We expect that FE will provide the required information within 9 months..

8.34 The following 2 tables show the ring fenced allowances for FE mains. These are split into new build and other mains as the cost per metre differs for new build as detailed in tables 13 and 14 of Appendix 4

Table 70 – Infill mains allowance for new build housing, FE

New Build Housing Mains	FE Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
New Build Pipe laid, km	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
New Build Average Cost per metre, £	*45*	*46*	*46*	*75*	*75*	*73*	*58*	*58*	*58*
Total, £k	655	665	659	1,084	1,080	1,051	833	833	833

Source: FE and the Utility Regulator

Table 71 – Other Mains Allowance, FE

Other Mains	FE Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Pipe laid, km	72.5	56.5	48.7	72.5	56.5	48.7	72.5	56.5	48.7
Average Cost per metre, £	*100*	*98*	*98*	*103*	*100*	*98*	*79*	*77*	*78*
Total, £k	7,274	5,533	4,771	7,446	5,633	4,791	5,698	4,327	3,779

Source: FE and the Utility Regulator

Pressure Reduction Stations

8.35 We reviewed the forecast activity volumes and costs associated with the construction of PRS installations. The levels are consistent with the historical actual performance and the intent to continue extending the opportunity for connection of domestic properties to the network. We therefore accept the forecast costs.

Table 72 – Pressure reduction station allowances, FE

Variable	FE Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
New PRS IP:(MP/LP)	0	0	0	0	0	0
New PRS MP:LP	25	15	15	25	15	15
Cost, £k	238	158	157	238	158	157

Source: FE and the Utility Regulator

Domestic Services

8.36 FE plans to connect 4,000 domestic customers in 2014 and 2015 and 3,800 in 2016, we have not applied any adjustment to the forecasts.

8.37 In its submission, the average cost per service to existing housing was £1074 and to new build was £414 although when restated as part of the comparative efficiency analysis, the rates were £897 and £498 respectively. The outcome of our performance comparison analysis is an allowance of £696 per service to existing housing and £387 to new build housing.

Table 73 – Domestic services allowance, FE

Variable	FE Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Existing housing	3,200	3,200	3,000	3,200	3,200	3,000
Cost per service existing, £	*1,065*	*1,080*	*1,078*			
New build housing	*800*	*800*	*800*	*800*	*800*	*800*
Cost per service new, £	*412*	*418*	*414*			
Total, £k	3,736	3,790	3,566			
	Restated Submission			Final Determination		
Cost per service existing, £	*907*	*904*	*880*	696	696	696
Cost per service new, £	*504*	*502*	*489*	387	387	387
Total, £k	3,306	3,293	3,031	2,537	2,537	2,398

Source: FE and the Utility Regulator

Domestic Meters

8.38 A meter will be required for all new connections, and FE indicate that no meters will be replaced during the GD14 period.

8.39 Our allowances are shown in the following table. As indicated previously, although the total capex allowance is consistent with the comparative efficiency analysis, due to the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar, some of the analysis outcomes at cost item level offer allowances that are greater than those requested or that are significantly lower. In the particular case of domestic meters, the cost per meter allowance is greater than the FE submission.

Table 74 – Domestic meters allowance, FE

Variable	FE Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Number of new meters	4,000	4,000	3,800	4,000	4,000	3,800
Cost per new meter, £	*198*	*201*	*199*			
Number of replacement meters	0	0	0	0	0	0
Cost/replacement meter, £						
Total, £k	793	805	755			
	Restated Submission			Final Determination		
Cost per new meter, £	*294*	*293*	*285*	226	226	226
Cost/replacement meter, £				226	226	226
Total, £k	1,176	1,171	1,084	904	904	859

Source: FE and the Utility Regulator

I&C Services

8.40 FE plans to connect 152, 102 and 52 I&C customers in 2014, 2015 and 2016 respectively, of these, 2 in each year are defined as large loads and the remainder small. This variation in mix of large and small I&C connections shows an increasing trend of the submitted cost per service over the 3 years.

8.41 In the FE submission the cost per service averaged £4,512, although when restated as part of the comparative efficiency analysis, this reduced to an average of £1,436.

8.42 The comparative efficiency analysis has been carried out based on the following size categories:

- Very Small (U6)
- Small (U16 – U40)
- Medium (U65 – U160)
- Large (U250 – U2500)

8.43 Our average allowance for each year of the period is £1,120 per service and the detailed results, including allowed unit cost for each load size, are set out in Table 15 of Appendix 4.

8.44 As indicated previously, although the total recommended capex allowance is consistent with the comparative efficiency analysis, due to the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar, some of the recommendations at cost item level offer allowances that are greater than those requested or that are significantly lower. In the particular case of I&C services, our allowance is significantly lower than the FE submission.

Table 75 – I&C services allowance, FE

Variable	FE Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
Number of connections	152	102	52	152	102	52
Average Cost per service, £	*4,433*	*4,527*	*4,576*			
Total, £k	674	462	238			
	Restated Submission			Final Determination		
Average Cost per service, £	*1,436*	*1,441*	*1,430*	1,153	1,129	1,078
Total, £k	218	147	74	175	115	56

Source: FE and the Utility Regulator

I&C Meters

8.45 A meter will be required for all new connections, and FE indicate that no meters will be replaced during the GD14 period.

8.46 The variation in the numbers and mix of large and small I&C meters mirrors that of I&C services and results in an increasing trend of the cost per meter over the 3 years in the submission. In the FE submission the cost per meter averaged £1,500, although when restated as part of the comparative efficiency analysis, this reduced to an average of £790.

8.47 The comparative efficiency analysis for I&C meters has been carried out based on a range of meter sizes from U6 through to U2500. As meter costs are dependent on load size, the unit costs over such a wide range could be expected to vary by 2 orders of magnitude.

8.48 Our allowance averages £723 for new meters and the detailed results, including allowed unit cost for each load size, are set out in Appendix 4 Table 16.

8.49 As stated previously, although the total recommended Capex allowance is consistent with the comparative efficiency analysis, due to the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar, some of the recommendations at cost item level offer allowances that are greater than those requested or that are significantly lower. In the particular case of I&C Meters, the cost per meter allowance is significantly lower than the FE submission.

Table 76 – I&C meters allowance, FE

FE I&C Meter Summary	PNGL Submission			Restated Submission			Final Determination		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Number of new meters	152	102	52	152	102	52	152	102	52
Average Cost per new meter, £	*1,413*	*1,481*	*1,606*	*779*	*789*	*803*	*818*	*735*	*616*
Total, £k	***215***	***151***	***84***	***118***	***80***	***42***	***124***	***75***	***32***
Number of replacement meters	0	0	0	0	0	0	*0*	*0*	*0*
Average Cost per replacement meter, £	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total, £k	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***
Total, £k	**215**	**151**	**84**	**118**	**80**	**42**	**124**	**75**	**32**

Source: FE and the Utility Regulator

Other Capex Items

8.50 The individual cost items under “other capex” are: IT & Office and Telemetry.

8.51 FE has requested £300k, £300k and £50k as allowances for 2014-2016 for IT and Office. In its original submission, FE states that £125k of the total amount requested was required in order to develop an automated switching system to facilitate full market opening in 2015. FE provided no justification for the remaining £475k over the three year period.

8.52 FE’s response to the draft determination now indicates the majority of the expenditure over the three years is required to develop a new Non Daily Metered (NDM) Model. We note that prior to receiving their response in September 2013, FE made no indication to us that they had any plans to develop a new NDM model. We have been clear at GMOG meetings that development of any new NDM model would need to be a solution covering all NI. Therefore we have not granted any allowance in relation to the NDM Model.

8.53 In the draft determination we allowed £100k ring fenced for an automated switching system to facilitate market opening. For the final determination we have continued to allow this amount and it will continue to be ring fenced in 2014. FE will be required to provide a detailed business plan to justify these costs.

8.54 In addition we have granted an allowance under the IT & Office cost line for fixtures and fitting amounting to £35k over the three year period.

8.55 For the final determination we have also granted an allowance of £10k per annum under a cost line named ‘network code’. This is in line with the allowance granted to PNGL. We wish to be clear that we expect FE and PNGL to work together along with gas supply companies in order to facilitate and improve competition and the allowances granted under the network code cost line should be utilised to assist in this objective. Should any other significant code modifications require an allowance we will consider business cases put forward.

8.56 In relation to telemetry, FE requested £38k, £37k and £25k in 2014 - 2016 to undertake an extension and upgrade of their current telemetry system. FE has provided some additional detail on the upgrades required.

8.57 We accept that the accuracy of telemetry equipment may have a greater importance to FE since market opening and based on the additional information received we are increased the allowance to £60k over the three year period.

8.58 We expect FE to produce a detailed report at the end of 2015 which details the improvements and upgrades that FE has carried out on its telemetry systems, along with the benefits and the costs incurred. We will consider this carefully at the next price control. We note that PNGL is also seeking to upgrade its telemetry systems and we therefore expect FE and PNGL to work together to find the most efficient and beneficial solution.

Traffic Management Act

8.59 As stated previously, in our analysis we have used cost and unit rates that do not include TMA. FE’s TMA forecasts have been retained as a separate cost line in the Capex summary table, which will better facilitate the retrospective adjustment at the time of the next price control.

FE Capex Summary Pre-Efficiency

8.60 In the table below we set out a summary of the total pre-efficiency capex allowances for 2014, 2015 and 2016.

Table 77 – Capex summary, £k – FE

Cost Item £k	FE Submission				Final Determination				Difference				
	2014	2015	2016	Total	2014	2015	2016	Total	2014	2015	2016	Total	Total, %
7 bar mains	0	0	0	0	0	0	0	0	0	0	0	0	n/a
New build housing mains	655	665	659	1,979	833	833	833	2,498	177	168	174	519	26%
Other mains	7,274	5,533	4,771	17,578	5,698	4,327	3,779	13,804	-1,576	-1,206	-992	-3,773	-21%
Pressure reduction stations	238	158	157	553	238	158	157	553	0	0	0	0	n/a
Domestic services	3,736	3,790	3,566	11,092	2,537	2,537	2,398	7,471	-1,200	-1,253	-1,168	-3,621	-33%
Domestic meters	793	805	755	2,354	904	904	859	2,667	111	99	104	313	13%
I&C services	674	462	238	1,374	175	115	56	347	-499	-347	-182	-1,027	-75%
I&C meters	215	151	84	449	124	75	32	231	-90	-76	-52	-218	-49%
Telemetry	38	37	24	99	25	25	10	60	-13	-12	-14	-39	-40%
IT & Office	300	300	50	650	112	12	11	135	-188	-288	-39	-515	-79%
Network code	0	0	0	0	10	10	10	30	10	10	10	30	n/a
Total excluding TMA	13,924	11,900	10,304	36,128	10,656	8,996	8,144	27,796	-3,278	-2,914	-2,170	-8,332	-23%
Traffic Management Act	1,147	958	854	2,959	924	781	707	2,412	-223	-177	-147	-547	-18%
Total including TMA	15,072	12,858	11,158	39,087	11,581	9,777	8,851	30,208	-3,501	-3,091	-2,317	-8,879	-23%
Pipe laid (km)	87.0	71.0	63.2	221.1	87.0	71.0	63.2	221.1	0.0	0.0	0.0	0.0	n/a
Connections (Domestic)	4,000	4,000	3,800	11,800	4,000	4,000	3,800	11,800	0	0	0	0	n/a
Connections (I&Cs)	152	102	52	306	152	102	52	306	0	0	0	0	n/a

Source: FE and the Utility Regulator

FE Capex Post-Efficiency

8.61 As detailed in chapter 14, we consider all capex including TMA to be controllable.

8.62 As detailed in chapter 14, we have applied the relevant compound Real Price Effect and ongoing productivity increase factors for each year to the controllable pre-efficiency capex allowance to establish the controllable post-efficiency capex allowance. This equals the overall post-efficiency capex allowance as the uncontrollable capex is £0 for each year of the price control period. Table 78 provides an overview of the results.

Table 78 – FE capex post-efficiency, £k

FE Capex (£k)	2014	2015	2016	Total
Controllable capex pre-efficiency	11,581	9,777	8,851	30,208
RPE and ongoing efficiencies	-517	-495	-508	-1,521
Controllable capex post-efficiency	11,063	9,282	8,343	28,688
Uncontrollable capex	0	0	0	0
Total capex post-efficiency	11,063	9,282	8,343	28,688

Source: FE and the Utility Regulator

9 ASSESSMENT OF FE VOLUMES FOR GD14

Update from Draft Determination

9.1 This section has not changed since the draft determination, with the exception of the removal of a significant proposed additional development area connection, due to the uncertainty of connection timings and volume usage. This removes approximately 9m therms from the overall volume target for GD14.

Introduction

9.2 FE volumes are important in setting determined allowances and FE is incentivised to outperform on volumes.

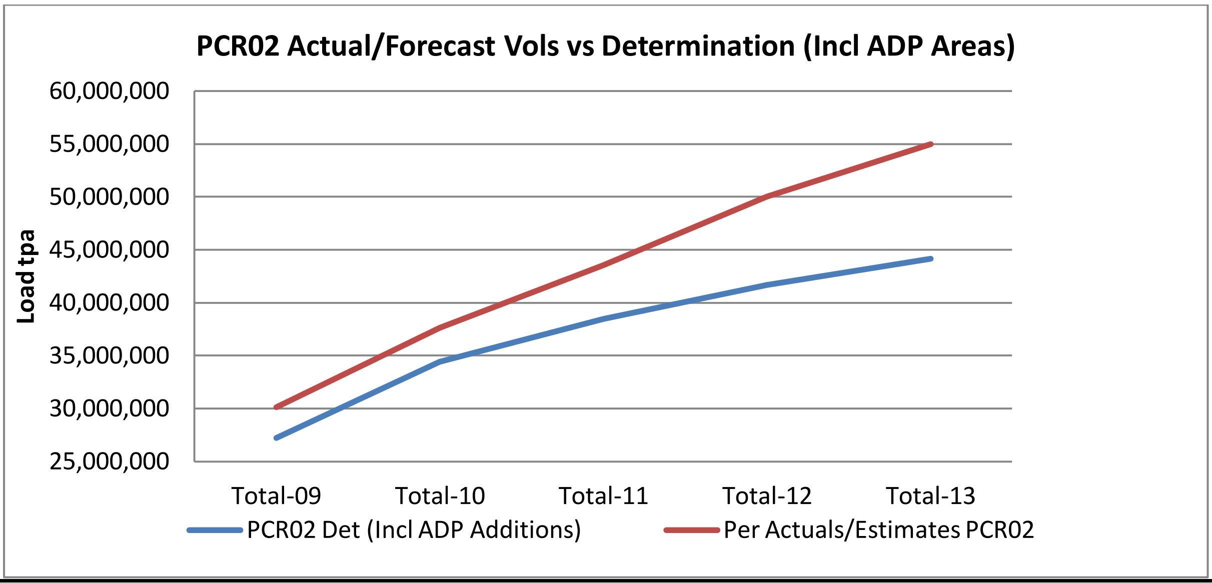
PCR02 Performance

Table 79 – PCR02 performance vs determination (inc. Additional Development Plan Areas)

therms	2009	2010	2011	2012	2013	Total
PCR02 Actual/Forecast Volumes	30,101,379	37,616,386	43,574,450	50,045,987	54,980,347	216,318,549
PCR02 Determined Values (incl ADP Areas)	27,234,488	34,426,400	38,495,629	41,648,926	44,170,225	185,975,669
Variance Outperformance / (Underperformance)	**2,866,890**	**3,189,986**	**5,078,821**	**8,397,061**	**10,810,122**	**30,342,880**
Variance %	**11%**	**9%**	**13%**	**20%**	**24%**	**16%**

Source: FE and the Utility Regulator

Figure 13 – PCR02 performance vs determination (including Additional Development Plan Areas)



Source: FE and the Utility Regulator

9.3 The above table and graph show that FE significantly outperformed against its volumes determination (2012/13 includes Additional Development Plan volumes) in all years of PCR02. This outperformance is very welcome and will flow through to customers in GD17 in the form of lower tariffs as we apply updated volumes.

Customer Additions Assumptions

Table 80 – Customer addition assumptions

GD14 Request	2014	2015	2016
P1 (Domestic Customer)	4,000	4,000	3,800
P2 (I&C Tariff Customer)	150	100	50
P3 (I&C Medium, Customer >25k therms, but < 75k therms)	2	2	2
Final Determination	**2014**	**2015**	**2016**
P1	4,000	4,000	3,800
P2	150	100	50
P3	2	2	2
Increase / (Decrease) vs Request	**2014**	**2015**	**2016**
P1	0	0	0
P2	0	0	0
P3	0	0	0

Source: FE and the Utility Regulator

9.4 The assessment of customer additions submitted by FE in the P1 to P3 categories (incorporating all Domestic, I&C tariff customers and Medium I&C customers) in the above table show additions to P1 of 4,000, 4,000 and 3,800, P2 shows a constant reduction, which can only be assumed as the result of a shift in focus of targeted connections and P3 is constant at 2 per annum from 2014.

9.5 The customer additions made by us compared to submission in relation to P4 to P6 categories are in respect of the a number of new extension areas where firmus GD14 submission differed from its own Additional Development Plan for those areas. We have used the numbers as previously submitted by FE and allowed by us. Other than that we have assumed no new net additional connections at this level.

9.6 We have also excluded a significant additional customer that was submitted by FE in their business plan due to uncertainty of connection timing and volume usage. We have taken this approach to set a prudent volume target. The impact is a reduction of approximately 9m therms from the draft determination.

Average Customer Burn Assumptions (Domestic and Small I&C)

9.7 In general, FE has assumed a steady decline in customer burns year on year from 2013. In our view is that this is not justified and burns assumed should not differ significantly over the short to medium term.

9.8 For these reasons, we have determined to set the burn for categories P1 to P3 at the rate forecast for 2013.

Table 81 – Average customer burn assumptions (P1 – P3)

GD14 Request	2013	2014	2015	2016
P1	394	391	395	395
P2	5,051	4,862	4,782	4,713
P3	42,207	41,194	41,136	41,056
Final Determination	**2013**	**2014**	**2015**	**2016**
P1	394	394	394	394
P2	5,051	5,051	5,051	5,051
P3	42,207	42,207	42,207	42,207
Increase / (Decrease) vs Request	**2013**	**2014**	**2015**	**2016**
P1	0	3	-1	-1
P2	0	188	269	337
P3	0	1,014	1,071	1,152

Source: FE and the Utility Regulator

Average customer burn assumptions (Large Contract) and 'general' closure

Table 82 – Average customer burn assumptions (P4 – P6) and 'general' closure

'General' Reduction of Volumes GD14 Submitted	2014	2015	2016
P3 (I&C Medium, Customer >25k therms, but < 75k therms)	-92,950	-188,020	-285,102
P4 (Large I&C Customer, Combined Heat & Power (CHP))	-83,425	-164,764	-244,070
P5 (Large I&C Customer, Firm)	-275,475	-544,063	-805,937
P6 (Large I&C Customer, Interruptible)	-606,400	-1,271,703	-1,883,810
Total Submitted Volumes (Incl Reduction)			
P3	3,718,000	3,808,000	3,898,000
P4	3,337,000	3,337,000	3,337,000
P5	11,019,000	11,019,000	11,019,000
P6 (excl 22.5 Int)	24,256,000	25,756,000	25,756,000
Reduction as a % of Total			
P3	2.5%	4.9%	7.3%
P4	2.5%	4.9%	7.3%
P5	2.5%	4.9%	7.3%
P6	2.5%	4.9%	7.3%

Source: FE and the Utility Regulator

9.9 The above table shows that FE have a 'general' reduction provision within its GD14 submission which relates to closures They have assumed a blanket percentage which compounds every year and reduces volumes significantly.

9.10 We maintain the view to exclude any 'general' reduction due to closures as applied by FE. The exclusion of any closures is matched by our assumption of no new large connections.

Interruption of Service

9.11 FE has assumed a reduction in volumes to reflect an average number of interruptions for interruptible customers of 22.5 days per annum.

9.12 We are not aware of any customers during PCR02 that experienced interruption to their supply. We see no reason why this pattern should change.

9.13 Therefore, in respect of the reduction for interruption assumed by FE as part of their GD14 request of 22.5 days per annum, we maintain our view to exclude any interruption allowance and set this at 0 days per annum for our final determination.

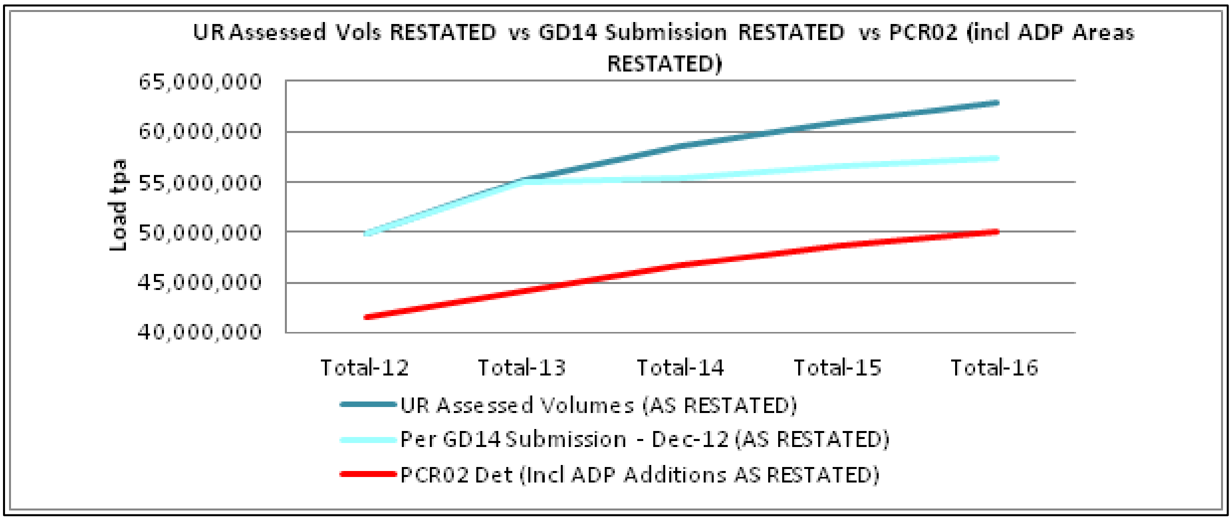
Final Determination of Volumes

Table 83 – Draft Determination of Volumes

	PCR02 Rebase	GD14			
therms	**2013**	**2014**	**2015**	**2016**	**Total GD14**
GD14 Requested Volumes (as restated)	54,980,347	55,442,606	56,498,752	57,376,549	169,317,907
Final Determined Volumes (as restated)	55,203,263	58,570,387	60,909,453	62,955,215	182,435,054
Variance Determination Increase / (Decrease)	**222,916**	**3,127,781**	**4,410,701**	**5,578,666**	**13,117,147**
Variance %	**0.4%**	**5.6%**	**7.8%**	**9.7%**	**7.7%**

Source: FE and the Utility Regulator

Figure 14 –Final Determination volumes vs GD14 submission vs PCR02 (inc. Additional Development Areas)



Source: FE & the Utility Regulator

9.14 Given the final positions on all of the aforementioned areas, the results are outlined in the table, and graphically, above.

9.15 The main areas being impacted in GD14 are P4 to P6 with an additional 0.8m therms added for GD14 (8.7m therms of which relate to P6) against submission (as restated). The P1 to P3 categories were increased by an aggregate of 2.3m therms against submission (as restated).

9.16 The trending from the graph above shows that we estimate rises as per the FE GD14 request, however, at a steeper rate, impacted by volume increases in new extension areas and annual burn assessments.

9.17 The volumes determined here have a significant impact in the reduction in FE tariffs compared to PCR02.

10 Adjustments from the Previous Price Controls, PNGL12 and PCR02

Update from Draft Determination

10.1 Since the draft determination, PNGLs TRV has been updated to reflect the removal of prepayment meters as outlined by the Competition Commission.

10.2 FEs TRV has been updated to reflect actual outturn numbers in relation to 2009 to 2012 and best available estimates in relation to 2013 outturn. Additionally we identified an error in calculating depreciation, we have removed an allowance for the Foyle river crossing which was not spent and removed a ring-fenced consultancy allowance in relation to market opening.

10.3 The FE under-recovery position has been updated to reflect 2012 actual outturn values.

Introduction

10.4 This section sets out the adjustments that result from the uncertainty mechanisms that formed part of the price controls preceding GD14 for both PNGL (PNGL12) and FE (PCR02). This is necessary so that we suitably adjust allowed revenues in the current price control consistent with these mechanisms.

10.5 More specifically, the adjustments considered in this section relate to the following:

- Retrospective mechanism
- The Total Regulatory Value (TRV)
- FE under-recoveries
- FE volume outperformance.

10.6 These are discussed in turn in the sections that follow.

Retrospective Adjustments

10.7 For both PNGL and FE a retrospective mechanism is in place which adjusts the previous price control determination based on outputs achieved (or in some cases allows some expenditure items to be treated as "pass through" costs).

10.8 The numbers provided below for TRVs at the start of the next price control period are after application of this retrospective mechanism (FE adjusted for 2009 to 2012 with 2013 estimated, PNGL updated to 2012).

10.9 In respect of the FE TRV, a 'special engineering project' allowed as part of PCR02 for the Foyle River crossing which has not been constructed has been removed as a retrospective adjustment. The PCR02 determination document stated *"the consumer should not be asked to finance the expenditure associated with the Foyle Crossing twice"*[37] and we note that FE has indicated that it is likely to request approval to

[37] Page 6 of the "firmus energy Price Control 02 'Determined to' Position December 2008*"* Document.

undertake this spend within the GD14 period. Note that no allowance has been made for this in the GD14 capex allowances, as the approval will be subject to us receiving a robust business case.

10.10 As well as the above we removed ring-fenced consultancy allowances, in relation to market opening, given in 2010 and 2011. This was to be granted subject to a business case being received from FE and approved by us, this did not occur.

10.11 It is also worth noting that we have provisionally included a retrospective adjustment in relation to NIHE spend incurred by FE in the 2013 year, capped to a maximum of £1.5m (2012 prices). We will finalise the quantum of this allowance, subject to receiving robust information from FE on this issue.

Total Regulatory Value, PNGL

Background

10.12 We set out in our February 2013 consultation on the PNGL licence modifications that we would carry out a full review of the treatment of the PNGL TRV as part of GD 14. To recap, the TRV was created in 2007 as part of a new licence regime. This licence for the first time contained a standard 'building block' regulatory model, including a price control mechanism based explicitly on a regulated asset value. The determination of an opening asset value (OAV) was incorporated in the licence, which led to the foundation of the TRV.

10.13 In 2007, the agreed value of the TRV was £312.8m (2006 prices). The CC considered the TRV components in its determination regarding PNGL12 and made a decision on what was appropriate for each element of the TRV. The CC's conclusions result in the TRV being set as £437.1m from 1 January 2012 (in 2010 prices). The TRV at this date consisted of the following components:

Table 84 – Composition of PNGL's TRV

Components	£ m
Net investment, less depreciation plus working capital	213.3
Historical under-recoveries of revenue (1996-2006)	73.0
Unspent allowances: including deferred capex and historical outperformance (1996 - 2006)	65.6
Profile adjustment	85.2
Total TRV	**437.1**

Source: PNGL and the Utility Regulator

10.14 Each of the components of the TRV is explained below.

- **Net investment, less depreciation plus working capital**

  This is the past investment that PNGL has undertaken from its inception in 1996 to 2011 in developing the network, which had not yet been paid for by customers. This component therefore represents actual costs incurred by PNGL, including working capital adjustments.

- **Under-recoveries of revenue**
  Revenue that PNGL was entitled to collect from customers between 1996 and 2006 was deferred and carried forward to later years because PNGL priced below the price cap (then applying) in an effort to encourage customers to switch to natural gas.

- **Unspent allowances**
  When we calculated the OAV in 2007 we rolled forward and capitalised the net present value of unspent opex, capex and working capital allowances (WCA) from 1996 to 2006. The main areas of unspent allowances can be broken down into two elements:
  - **Deferred capex –** specific, bulk capex projects that were deferred from 1999/2000 to later years. The CC's decision in relation to this was as follows: (i) PNGL was allowed to retain all of the financial benefit of deferring projects that were subsequently completed by the end of PC03 (i.e. 2007); (ii) projects that were not completed by the end of PC03 were to be removed from the TRV. The CC also decided that the TRV be adjusted downwards to remove the capitalised financing benefit that accrued to PNGL since 2007.
  - **Historical outperformance** - the CC decided that PNGL should be allowed to keep all of its other under-spending in the TRV during PNGL12, apart from the allowances for business rates, which were to be removed as PNGL had been funded twice for the same expense.
- **Profile adjustment**
  This is revenue carried forward to future years to maintain an even price profile over time. This element of the TRV ensures that conveyance charges are not unduly high in the early phases of the gas market's development. In practice, PNGL currently defers an element of its revenue entitlement into the future. The recovery of this deferred revenue is secured for PNGL by way of an addition to the regulatory asset base, via a mechanism enshrined in its licence known as the 'profile adjustment'. The profile adjustment builds up over the course of each respective price control period, and then forms part of the asset base at the beginning of successive reviews.

10.15 The breakdown of the TRV shown above provides clarity regarding the components that constitute the TRV as we think it is helpful to all stakeholders to be transparent about the origins of PNGL's regulated asset base.

10.16 The CC was clear that its decision in the recent inquiry only applies to 2012 and 2013 and that further decisions on how to treat all these matters beyond 2013 will be made by us in accordance with its statutory duties. The CC stated in its PNGL12 price determination in paragraph 9.109:

> "We should observe, however, that our decision covers only two years and we do not wish to trespass on to the territory of future regulatory reviews (where other issues or evidence may be relevant). This is especially the case in a decision such as this where the specific context has been highly important to our reasoning."

10.17 This section considers the appropriate value of PNGL's TRV from 1 January 2014.

10.18 The net investment amount is recognisable as a standard GB RAB and there are no specific issues around how it is treated.

10.19 The profile adjustment is a mechanism that provides for levelised tariffs in a growing market. There are also no issues in how this is handled.

10.20 Historical under-recoveries of revenue are an unusual feature of the PNGL TRV and represent revenue which PNGL was allowed to recover between 1996 and 2006. These have been allowed in the TRV despite the original licence requiring them to be fully recovered by 2016. We are also aware that other regulators have not allowed such under-recoveries to be recovered e.g. the Civil and Aviation Authority in the BAA Stansted 2007/08 review. However, we view this matter as having been fully dealt with in 2007 and we do not see any issues that need to be further considered now.

10.21 Historical unspent allowances are one area of the TRV that requires clarity as to how it will be treated in future. This was the main area of the CC inquiry in 2012, which as mentioned above, determined how this should be treated for the PNGL12 control period (i.e. 2012 and 2013); below, we set out our views on the options for dealing with it for the GD14 period and beyond. The issue of deferred capex is considered separately further below (from paragraph 10.36).

Historical unspent allowances

10.22 The full amount of unspent allowances was allowed in the TRV in 2007. Our original intention was that this component would later be removed from the TRV, so that historical outperformance could be shared with customers based on regulatory practice elsewhere. However, the CC considered (and we accept) that our intentions in this regard could have been better signalled in advance. When we proposed to adjust the TRV in PNGL12 i.e. after PNGL had obtained five years of benefit from its outperformance, PNGL objected and sought a reference to the CC.

10.23 The CC's findings on this issue are set out in section 9 of the final determination issued by the CC. It is important that we take this reasoning into account in making any decision.

Removing historical outperformance from the TRV

10.24 The reasons for the CC conclusion were summarised in section 9.108 of its final determination which states *"where we differ from UR is where, within the overall view of the public interest, we strike the necessary balance between prices that customers pay, network development and the appropriate reward for the development of the network in the context of a still maturing industry".*

10.25 Formally the CC's decision relates to the value of the TRV in 2012 and 2013 only. It was not within the CC's terms of reference to determine the value of the TRV from 2014 onwards. We have nevertheless considered the appropriate approach for GD14 against CC's criteria.

Risk and Reward

10.26 The CC determined that "the risks of PNGL's undertaking should be sufficiently rewarded" (paragraph 9.81 of the final determination).

10.27 We recognise that the CC considered this as part of its inquiry and determined that it was fair reward for PNGL to collect the full outperformance amount from its customers.

Network development

10.28 It is clear in its conclusions that the context of network development played an important role in the CC's final determination. The CC thought that it was possible that investors could refuse to invest in gas extensions. We have now had an opportunity to observe evidence in this regard since our 2011 proposals on the TRV. If anything, levels of interest in gas development have never been higher. Since 2011 we have received requests for six additional development areas or licence extensions. These include extensions of the network in Coleraine, Bushmills, Glenavy, Bessbrook and Camlough.

10.29 We have also witnessed gas connections increasing significantly in the PNGL and FE areas with over 14,000 connections. As well as this, we have had extensive discussions with multiple investors in relation to the 'Gas to the West' project and the sale of PNGL and FE. While this demonstrates the high level of interest in gas continues, the level is not significantly different from when the CC made its decision.

Consumer impact

10.30 The duty to protect consumers is an important issue for us and this is incorporated in our principle objective through the IME3 changes to legislation. The CC noted in its final determination that its proposals would increase costs by about 2% and that this would have a negative impact on consumers and industry.

10.31 The CC also looked at the potential impact of regulatory instability on the WACC and thus on consumer bills over the longer run. The CC concluded in 9.120 that there was an element of regulatory instability and that this has material consequences that should not be disregarded. However, the CC could not quantify this effect.

10.32 The magnitude of any potential consumer impact has not changed significantly since the CC made its decision.

Conclusion on removing historical outperformance

10.33 In assessing the options regarding the treatment of historical outperformance, we have placed significant weight on the reasoning in the CC's decision on PNGL12.

10.34 We conclude that it is in the best interests of the industry and consumers to draw a line under the debate about the value of the PNGL TRV. This means that we will roll forward the TRV without modification in GD14. It is also our intention to allow PNGL to collect the full value of the TRV through subsequent price controls.

10.35 Retaining such an unusual TRV has implications for the appropriate WACC, as we discuss later in section 12.

Deferred capex

10.36 As mentioned above, in November 2012 the CC reported its conclusions on its investigation of the 2012 price determination for PNGL: 1999/2000 capex deferrals completed in PC03 were left unadjusted in the TRV, but 1999/2000 capex deferrals not completed in PC03 were removed from the TRV, including the capitalised financing adjustment from 2007.

10.37 PNGL has requested that a number of the excluded deferred projects be included within the capex allowances in future years. The CC report provided no clear guidance as to how the CC considered that this should be dealt with.

10.38 We have received comments on this from CCNI and PNGL. We understand CCNI concerns that this will mean customers paying twice. While we note the references PNGL has made to the CC determination, we do not agree that the CC ruling provided any clear guidance on this matter.

10.39 On balance we have decided to draw a line under this matter and have concluded that we will not make any adjustments in future to reflect previous rewards PNGL has received.

Current Total Regulatory Value, PNGL

10.40 The opening TRV that we have used in relation to 2014 is £503.6m[38] (2012 prices).

[38] This includes an adjustment downward of £0.3m in relation to removal of prepayment meters outlined by the Competition Commission. A recently updated estimate of the TRV reflecting outturn data up to 2012 is £500.4m (2012 prices), however, we will adjust the TRV to incorporate both outturn of 2012 and 2013 performance as part of the GD17 price control review.

Total Regulatory Value, FE

10.41 PCR02 set out the intent to implement a "retrospective mechanism" to adjust TRV based on the difference between allowances and outturn for some items. A number of documents and letters, including the PCR02 final determination, the supplemental market development review and letters approving extensions have clarified how the retrospective mechanism will be applied.

10.42 We have calculated the impact of the retrospective mechanism and as a result the opening TRV in 2014 is £117.5m (2012 prices).

FE Under-Recoveries

10.43 FE is set a determined tariff in each year but has some discretion in setting actual tariffs. In advance of market opening, FE distribution tariffs are calculated on a netback calculation which equals total revenue from customers minus transmission, gas and supply costs.

10.44 FE has been setting tariffs below allowance. FE had a cumulative under-recovery of £19.4m at the end of 2012 (2012 prices) based on the difference between actual and determined tariffs. We will approve increases in FE tariffs in future to recover this under-recovery amount.

10.45 The reasoning behind the inclusion of under-recoveries in the licence was to allow FE flexibility to ensure gas was competitive versus oil as it built its customer base. However the period during which FE has built up this large under recovery was one where gas prices were largely cheaper than oil and at times over 30% cheaper. This raises question as to the motive of building up such large under recoveries.

10.46 FE receives a 7.5% return on under-recoveries and is entitled to recover total under-recoveries by future increases in tariffs above determined tariffs. We believe the 7.5% return is providing a perverse incentive for FE to under-recover revenues.

10.47 One way of addressing this issue is to reduce the return allowed on under-recoveries in GD17. This could reflect the fact that there is no risk associated with these under-recoveries and hence it is against customers' interests to retain a full return on them. Furthermore, the impact of large under-recoveries is that today's gas customers are underpaying and are effectively subsidising future customers, which is inappropriate.

10.48 The FE licence contains a designated parameter which can be used to adjust the return allowed on under-recoveries below the allowed cost of capital. The licence has this set to zero until 2034 and it would require a licence change to enable us to set a value above zero which would have the effect of reducing the return on under-recoveries below the allowed cost of capital.

10.49 We recognise that FE has adopted a policy of building up under-recoveries in the expectation of achieving a return on these under-recoveries and consequently we are not altering the return on under-recoveries in GD14.

10.50 However, we will consider future licence modifications to reduce the return on under-recoveries in GD17 and we will also carefully review FE actions in reducing the under recovery amount before 2017. We believe our determination contained herein provides a reduction in determined tariffs from 2014 which will provide flexibility for FE to considerably reduce or even to eliminate the under-recovery by 2017.

10.51 We received comments on this matter from FE who argued that they should be allowed to retain the full rate of return on under recoveries. However nothing in the

FE response has convinced us that allowing a full rate of return does not create perverse incentives to build up under recoveries. We also note that PNGL has a different rate of return applied to over recoveries.

10.52 Therefore we note that we are minded to review the allowed return on under-recoveries in GD17 to ensure there are no perverse incentives and if this requires a licence modification we will consider this at that time.

11 Recommendations of Competition Commission Determination on PNGL12

Update from Draft Determination

11.1 This section has been updated for the change in TRV relating to prepayment meters discussed in the previous section and for our decision on whether to move to calculating cash flows mid-year.

Background

11.2 This section considers the recommendations arising from the CC's report which was set out in section 10 of its determination[39].

Timing of cash flows

11.3 The CC noted that the Phoenix licence assumes that all income and expenditure is at the year end. In practice, according to Phoenix, capex and opex are fairly evenly spread across the year and revenue is weighted towards quarters 1 and 4 when the weather is colder. The CC notes that this means that PNGL receives revenues slightly higher than necessary. The CC suggests that we should consider changing our modelling to assume mid-year revenues and shifting from the assumption of end year cash flows.

11.4 We have noted the CC's suggestion and the fact that we apply a mid-year calculation for PNGL. Following representations from PNGL and the fact that the impact of changing to mid-year cash flows would be value neutral as an adjustment to TRV would need to be made to compensate for the impact of the change, we have decided not to change the way we model cash flows.

Connections Incentive

11.5 The CC notes that under the original price cap, PNGL had strong incentives to connect customers; this incentive was lost when a revenue cap was introduced. The CC believes that the current connections incentive is lower. The CC recommended that we analyse whether the incentives for connections have reduced and consider whether changes should be made to the connections incentive or to any other part of the regulatory framework.

11.6 We have addressed this issue by developing a connections incentive which is described in section 5.

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[39] Competition Commission's Phoenix Natural Gas Limited price determination, 28 November 2012: http://www.uregni.gov.uk/publications/competition_commission_final_pngl_price_determination

Capex 2007 to 2011

11.7 The CC commented that the financial model did not include 2007-11 capex in DAV but noted that the impact on charges was immaterial in the current period but suggested that we review this treatment.

11.8 The treatment beyond 2011 is correct as capex is added to the DAV.

11.9 We have made no changes to the financial model for this.

Capex Overspend

11.10 The CC stated that 2009 capex overspend should be added to DAV in 2014, consistent with the rolling incentive mechanism. This is included in the retrospective mechanism and has been incorporated into the TRV figure set out in section 10.

TRV Adjustment for Prepayment Meters

11.11 The CC noted an error of £147k in 2006 prices in the TRV because we calculated the prepayment meter allowance based on actual P1 connections rather than forecast P1 connections as it had stated – a difference of 9,294 meters.

11.12 We noted our intention to review the modelling of prepayment allowances in the Draft Determination and we have adjusted the TRV downwards accordingly in the Final Determination for the prepayment meter error.

12 FINANCIAL ISSUES

Update from Draft Determination

12.1 This chapter has been changed to reflect recent comments made in consultation responses. It also takes into consideration the Competition Commission's provisional determination on Northern Ireland Electricity's RP5 price control in November 2013. TRV's have been updated in line with chapter 10. Furthermore, the section on financeability has now been moved to a separate chapter (see chapter 13).

Introduction

12.2 The determined opex and capex allowances, as set out in earlier sections, feed into a regulatory model which calculates the allowed revenues over the control period. As well as capital and operating expenditure, vital elements of determining the reasonable cost of service (and hence allowed revenues) are:

- The return *on* capital – this is the return required by debt and equity holders to finance the investment in capital assets. This return applies both to the existing asset base and new capital expenditure (as determined in the earlier sections); and
- The return *of* capital – this is broadly the cost of replacing existing assets when they reach the end of their useful life and is generally measured by a depreciation charge that records the reduction in value of the assets over time.

12.3 Accordingly, this section of the paper focuses on these key components of the regulatory model for both PNGL and FE, namely:

- Weighted average cost of capital (WACC); and
- Depreciation.

Weighted average cost of capital, PNGL & FE

Allowed rate of return

12.4 In section 10, we established that the value of the PNGL TRV to 2014 is £503.6m (2012 prices) and the value of the FE TRV in 2014 is £117.5m (2012 prices). These amounts can be thought of as the equivalent of 'I.O.U.s' from customers to the companies – i.e. a regulatory entitlement to collect a certain amount of revenue via future price controls.

12.5 Payment by customers will be over a number of years. This profiling requires us to provide both PNGL and FE with an annual rate of return, the value of which should make the companies broadly indifferent to the long payment period.

GD14

12.6 Both GDNs have licence conditions that set the rate of return until the end of 2016 at 7.5% (in real, pre-tax terms). This pre-announced rate has been an important reference point for PNGL and FE in their recent investment decisions and hence we have not adjusted this level of return in GD14.

12.7 However, we note that this rate is substantially higher than the return allowed for comparable GB network utilities. Nevertheless, we have made the decision to leave the rate of return unchanged, although our position for GD14 should not be seen as setting a precedent for future price controls.

GD17

12.8 Although we do not need to make a final decision on the rate of return at GD17 as part of this review, we viewed it would be helpful to all stakeholders for us to provide a brief overview of the issues that the regulator expects to have to deal with.

12.9 Our expectation is that we will set an allowed cost of capital in GD17 commensurate with the risks that we believe PNGL and FE face going forwards. This will use the Capital Asset Pricing Model (CAPM) and will take into account best GB regulatory practice and any relevant decisions by other regulators. As PNGL and FE are now much more mature and stable businesses, we anticipate that the allowed rate of return will be set more in line with the rates set for comparable GB utilities.

Cost of Capital

12.10 We note that in its GDN price control announced in December 2012, Ofgem set an allowed cost of capital of 4.2% post-tax, equivalent to 4.83% pre-tax.

12.11 We also note that the Competition Commission's provisional determination for Northern Ireland Electricity published in November 2013 has proposed a "vanilla" WACC of 4.1%, equivalent to a pre-tax WACC of 4.7%.

12.12 We do not believe that the risks facing NI GDNs are substantially different to those facing GB GDNs. For GD17, we propose to assess the risks that PNGL and FE face to set an appropriate cost of capital. For now, we have set out some initial thoughts.

12.13 As we discuss in paragraph 10.12 onwards, it is of note that the TRV for PNGL is composed of four separate elements:

- investment in physical assets;
- deferred revenue (the profile adjustment);
- revenue under-recovery (from pre-2007); and
- unspent allowances (including deferred capex and historical outperformance).

12.14 FE's TRV includes the first two of these elements. For GD17 we will undertake a detailed risk assessment to determine the appropriate rate of return taking into account the risk profile of the separate elements of TRV.

12.15 The first category is consistent with GB GDN's RAVs which are comprised almost exclusively of the value attributable to historical financial investment by shareholders/lenders. Consequently, for this category of TRV the risk of NI GDNs can be compared to the risk of GB GDNs to determine the relative risk and hence an appropriate return. However, the other three categories would not appear in a standard GB GDN RAV and would appear to be lower risk. We will need to consider the impact on the WACC.

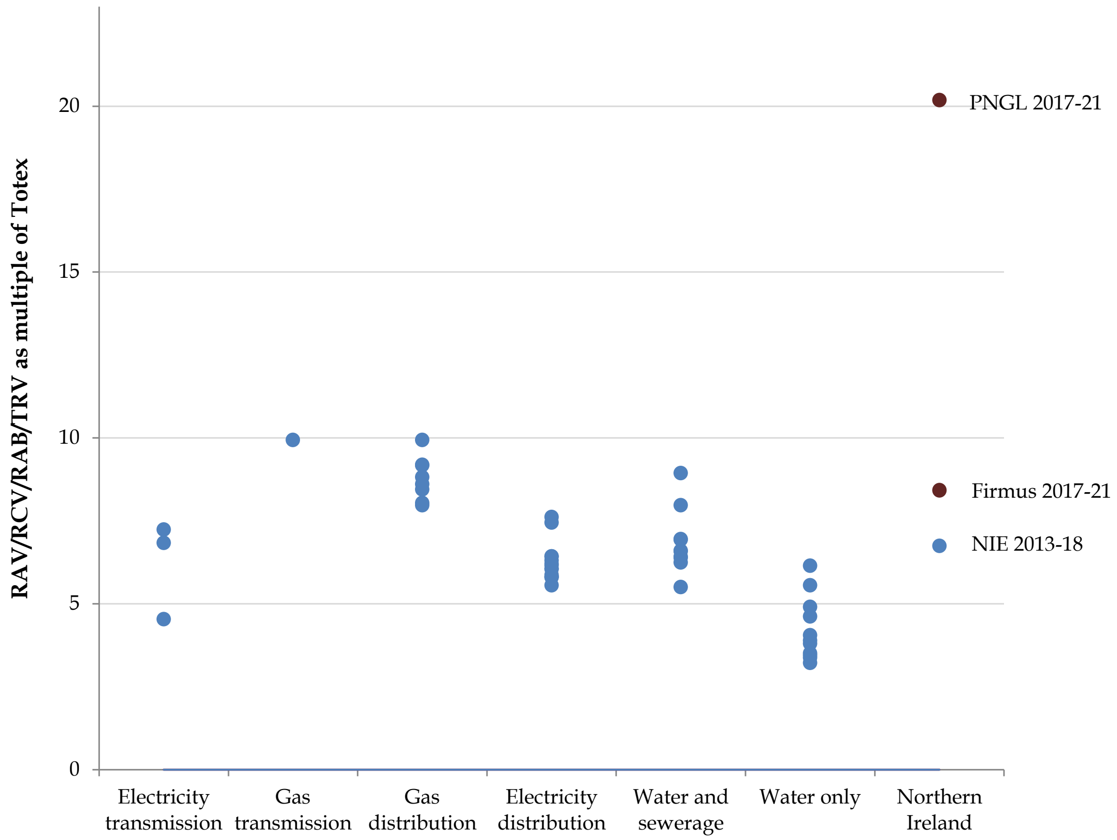
12.16 In PNGL's case there is a substantial historical outperformance amount. This does not represent actual monies that shareholders/lenders have put into PNGL and which needs at some point to be recouped from customers. Rather, it is an artificial creation; a regulatory entitlement to a monetary reward, the value of which is known with certainty but which shareholders cannot claim in full until 2046.

12.17 This makes PNGL's TRV look very different from normal RABs. As an illustration of this, we can compare the size of the PNGL TRV relative to ongoing opex/capex to ratios that exist in other sectors. One measure is the size of capex relative to TRV. The ratio 'capex : RAV' has been important in Ofgem's setting of the equity beta in recent price controls. For example, Ofgem in its recent GDN price control (RIIO:GD1) stated in relation to comparative risk assessment across network businesses that:

"In particular, we noted that GDNs had a lower capex : RAV ratio than Transmission Owners (TOs), which supported a lower allowed return"[40].

12.18 Regulators, again such as Ofgem in RIIO-GD1, frequently look at asset values as a multiple of total capex and opex (totex) to determine the risk of network utilities – broadly the higher the ratio the lower the risk. The chart below compares PNGL's and FE's asset value as a multiple of totex with that of a number of UK utilities.

Figure 15 – Regulated asset values as multiples of totex across UK regulated sectors



Source: The Utility Regulator

12.19 It is noteworthy that the ratio is far higher for PNGL than other utilities, suggesting that the risk it faces is lower. FE is at an earlier stage in the development of its network and consequently the proportion of its value represented by deferred revenue is smaller. Hence the cost of capital in GD17 will take into account this reduced risk compared to other networks.

[40] Ofgem, "RIIO-GD1: Final Proposals – Overview", 17 December 2012, pp. 34-35.

12.20 This approach could in theory lead to a position where the WACC is lower than for GB GDNs. This could give rise to a presentational issue whereby the risks of new investment is similar to that in GB, but the WACC is lower – as a result of the lower risk in the overall TRV.

12.21 An alternative to this approach is to recognise explicitly that the current TRV is made up of very different components which have different opportunity costs of capital.

12.22 Given these different characteristics, we consider that there is merit in exploring whether the TRV should be divided into a conventional RAB and a separate "pot" with regulatory commitment to be recoverable from consumers. The values of these two pots would sum to the current TRV to ensure no loss of value. The RAB would then attract a normal regulated company rate of return and the remainder of the TRV would roll up at a lower rate to reflect relevant risk. However we would also recognise that investors are more used to a single WACC and so may prefer the traditional approach.

12.23 There is some regulatory precedent for an approach which involves separating RAB into more than one pot. For example, Ofcom consulted on and concluded that BT's copper access business was lower risk than the remaining BT business and assessed that the group beta of 1.1 should be split as an equity beta of 0.9 for the copper access business and 1.23 for the rest of BT. Today, BT Openreach has a lower WACC than the remainder of BT.

12.24 The two alternatives set out above would point to a very similar amount of profit for NI GDNs in £m. The key difference is the presentation of this amount. A final decision will not be required until GD17.

12.25 A number of parties responded to this point and are dealt with more fully in the responses to responses. We remain of the view that taking into account totex:RAB ratios will be an important part of GD17 and may, for example, lead to a lower WACC for PNGL than GB GDNs.

12.26 We have noted comments on whether different 'pots' would assist in making the WACC more transparent and have not reached any conclusion on this. We will continue to consult on this issue before a final decision is made in GD17.

Risks within GDNs

12.27 In discussions with investors and in the responses to the consultation, the question of the level of maturity of PNGL and FE has arisen. For the purposes of understanding risk, one measure of an immature gas distribution company is one with high levels of capex relative to TRV and/or one which is dependent on future connections for its economic viability.

12.28 We have already set out above the level of totex relative to TRV which does not suggest companies with particularly high levels of capex. In relation to future connections, both PNGL and FE currently have their tariffs set on the basis of increasing connections and volumes. Certainly in the early years of development there is a real risk that these connections and volumes will fail to materialise and put at risk the recovery of allowed revenues.

12.29 We have analysed the risks for both companies from connections and volumes falling below forecast. However any fall in connections would also be associated with a fall in both capex and opex. The vast majority of connections remaining are for domestic properties and these are very marginal connections i.e. the revenues from the connection just about cover the costs of the connection. If we take an extreme case and assume no more connections from 2014 onwards, our analysis indicates that this would result in a very modest change in final bills to consumers. This compares to the volatility in final bills from the commodity cost of gas, where we approved increases of up to 39% in recent years.

12.30 Hence tariffs are not very sensitive to a fall in connections and there is no real risk of a large spike in charges risking recovery of revenues. We can conclude that now that all large industrial loads are connected, the maturity of PNGL and FE, in terms of failing to make future connections putting revenues at risk, is very similar to the GB GDNs.

12.31 FE currently faces additional volume risk under its licence and this would have to be taken into account in GD17. However, we note in section 16 that we will be undertaking a high level review of licences as part of GD17 and one issue will be whether a price cap is still appropriate for FE or whether, like PNGL and GDNs, it should move to a revenue cap.

12.32 We have also noted the PNGL submission to the CC in relation to the Northern Ireland Electricity (NIE) reference[41] which included a detailed review of PNGL's cost of capital and views on how default risk should be incorporated into any overall cost of capital. It also raised the issue of the risk around deferral of income. This is something which we will give consideration to along with all other comments we receive in advance of making a final decision in 2016.

12.33 While some of the responses covered this area none disputed the analysis that risk associated with connections was not significantly different from GB levels. In addition we have also noted that since the draft determination the CC has set out its provisional determination for NIE which includes its views on risk and WACC. The proposed WACC for NIE is below the 4.83% that Ofgem set for the GB GDNs. We will take regulatory precedents into account when considering these matters in GD17.

Cost of Equity

12.34 We note that in its GDN price control announced in December 2012, Ofgem set an allowed cost of equity of 6.7% post-tax, equivalent to 8.38% pre-tax. We would also note that the CC's provisional determination for NIE has proposed an allowed post-tax cost of equity of 4.8%, equivalent to 6.0% pre-tax.

12.35 We do not believe that the risks facing NI GDNs are substantially different to those facing GB GDNs. For GD17, we propose to assess the risks that PNGL and FE face to set an appropriate cost of equity. For now, we have set out some initial thoughts.

12.36 As neither PNGL nor FE are publicly traded entities we do not have a market based cost of equity on which to rely and will follow standard regulatory practice in assessing the risks of the companies discussed above in setting an allowed cost of equity.

Cost of Debt

12.37 We note that Ofgem has indexed the cost of debt for GB GDNs to enable GDNs to recover efficiently incurred debt costs based on an index of comparable companies' debt costs. In accordance with Ofgem's methodology, the allowed cost of debt for 2013/14 was 2.92% pre-tax giving GDNs a 'vanilla' WACC of 4.17% (based on 65% gearing), equivalent to a pre-tax WACC of 4.83%.

12.38 For PNGL and FE there are a number of options we will consider in relation to setting the cost of debt.

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[41] PNGL submission in relation to CC's inquiry into NIE's RP5 price control: http://www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/130604_phoenix_natural_gas.pdf

12.39 One option is to use CAPM to set an ex-ante allowance for debt for the whole of GD17. This option could be seen to be in line with the discussions on risk above where the cost of debt is built up based on the risk assessment of the GDN. This option would leave more of the debt risk with GDNs and less with consumers.

12.40 A second option would be to use an indexed methodology in line with what Ofgem has introduced in RIIO. This would have the benefit of being consistent with other GDNs in the UK. However we would have to take into account the size of the GDNs and the number of bond issues they are likely to have and if this has a bearing on the appropriateness of using a benchmark.

12.41 A third alternative is to use a specific company-related cost of debt. However, FE does not currently have its own debt and the PNGL debt is due to mature in 2017, which would not make it a useful marker for the cost of debt for the 2017-2021 price control period. We would be able to use the PNGL market cost of debt in 2016 at the time the decision for GD17 is made. However, if PNGL were to subsequently raise debt in 2017 this option would give rise to the risk that these values could be very different and we would need to give some thought to how this could be managed. This option has the benefit of simplicity but we would need to be assured it would produce an accurate reflection of the risks of the GDN and not reflect other risks inherent in the particular debt instrument the GDN's choose to use.

12.42 We note PNGL and FE's comments which included:

- A cost of debt premium applies for PNGL over and above GB GDNs;
- Debt should be set ex ante;
- transaction costs should be included; and
- there should be "headroom" allowed on top of a market benchmark in case debt costs increase.

12.43 We note that we are not making any decisions now but we expect to consult on our methodology for setting the cost of debt, and hence the allowed cost of capital, during 2016.

Assumed Return for Profiling Revenues

12.44 In GD14, and <u>for modelling purposes alone</u>, we have used a cost of capital in the financial model of 7.5% through to 2016 and 4.83% from 2017. This latter rate, consistent with the rate Ofgem set in RIIO-GD1, is an estimate to provide a more realistic assessment of the revenues for PNGL and FE beyond 2016 but should not be seen as a precedent for our decision in GD17. This approach follows our setting of the figure in 2007 at 5.83% which, at the time, was also the GDN rate allowed by Ofgem.

12.45 A number of responses questioned this assumption. However we continue to view it as reasonable and realistic and we note that it is below the rate proposed by the CC in its provisional determination for NIE. We have been clear that it is not a precedent for GD17 and we have set out above some arguments as to why FE and PNGL could have a higher or lower risk profile than GB GDNs.

Depreciation

12.46 For PNGL, future assets still to be constructed are depreciated in our regulatory model using a straight-line methodology over a range of periods, as follows:

- mains – depreciated over 40 years;
- services – depreciated over 35 years;

- meters – depreciated over 15 years; and
- all other capex – depreciated over 40 years.

12.47 For the 2007 opening asset base, in its submission PNGL proposes a straight-line methodology over 32 years i.e. the number of years left of its licence recovery period from 2014.

12.48 For FE, future assets still to be constructed are depreciated in our regulatory model using a straight-line methodology over a range of periods, as follows:

- Mains and services – depreciated over 40 years;
- Meters, pressure reduction stations and telemetry – depreciated over 15 years; and
- All other capex – depreciated over 5 years.

12.49 We note the differences above between PNGL and FE.

12.50 We have considered responses to this and given the minimal benefit at this time for the effort required by us and GDNs to adjust depreciation rates we have decided not to align the depreciation periods in GD14. We will look to align them in GD17 after full consultation.

13 FINANCEABILITY

Update from Draft Determination

13.1 The section on financeability was previously contained in chapter 12. Since the draft determination it has been fully revised and enhanced to include the assumptions used in our financeability modelling and details of the output of this model, both base case and downside scenarios.

Introduction

13.2 Article 14 of the Energy (Northern Ireland) Order 2003 requires us to carry out our functions in the manner we consider is best calculated to further our principal objective: having regard to the need to secure that licence holders are able to finance their licence obligations[42] (amongst other things).

13.3 This duty is framed similarly to the financing duties of other UK regulators and, as described in a recent Joint Regulatory Group statement (JRG statement)[43], can broadly be taken to mean that the price control will be set at a level which would allow an efficient company to finance its licensed activities. It is therefore necessary for us to consider financeability as an integral part of a price review.

13.4 We would note that a company needs to be able to finance its functions as a stand-alone business and hence the group structure should not be an issue in assessing financeability. Consequently our modelling has modelled PNGL and FE as stand-alone entities. This is discussed further in the financial modelling assumptions below.

13.5 We recognise that maintaining financeability is not only an obligation on the Regulator but is also in the consumer interest, since consumers are ultimately exposed in the future to the effects of any higher cost of capital.

13.6 In our draft determination we stated we were comfortable that the companies would remain on a financially sustainable trajectory. We also indicated our intention to continue developing our assessment of financeability, and would carefully consider feedback from respondents to the consultation.

13.7 Our draft determination explained the context for the financeability assessment, the financial indicators that are important in considering financeability and the rationale why these would be met within GD14. We have now undertaken comprehensive modelling, both for GD14 and beyond through to the end of the license recovery period, including sensitivity analysis. The details are described further below.

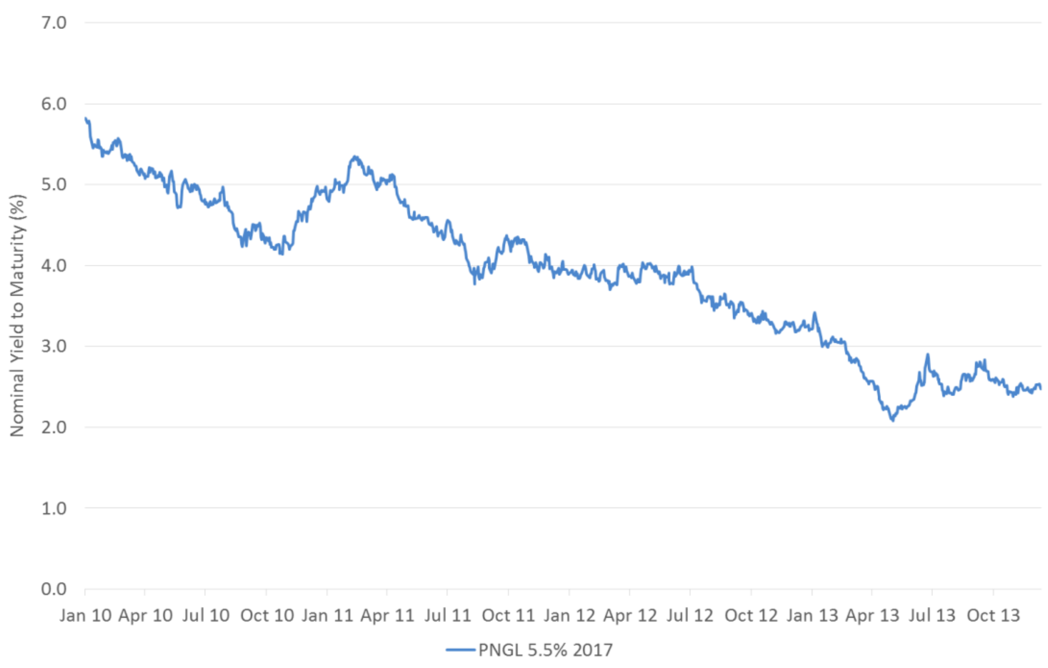
13.8 The remainder of this chapter describes the background to PNGL and FE and the differences between them; the financial indicators that we focus on; our financial modelling assumptions; and the results of our financeability modelling, both base case and sensitivity analysis.

[42] Activities which are the subject of obligations imposed by or under Part II of the Gas (Northern Ireland) Order 1996 or the Energy (Northern Ireland) Order 2003.
[43] See paragraph 2.2 of 'Cost of Capital and Financeability', a statement of the Joint Regulators Group (JRG), Ofgem, March 2013.

13.9 PNGL has recently changed ownership and was purchased on 5 August 2013 by a joint venture consisting of Hastings Fund Management, an Australian specialist fund manager of infrastructure equity and debt and Royal bank of Scotland Pension Fund.

13.10 PNGL has a £275m bond, issued by Phoenix Natural Gas Finance, which is due for repayment in 2017. The bond is rated as Baa2 (stable) by Moody's and as BBB+ by Fitch. The graph below shows the yield to redemption of this bond.

Figure 16 – Yield to Redemption PNGL 5.5% bond maturing 2017



Source: Bloomberg Data

13.11 Note that the yield to redemption of PNGL's bond has declined from over 5% at the start of 2011 to below 3% currently.

13.12 The gearing of PNGL (defined as the ratio of net debt to total regulatory value) declined from just under 70% in 2009 to around 55% in 2012. On 26 June 2013, PNGL refinanced its current bank facilities and in addition paid a £90m dividend to shareholders. The impact was to increase gearing back to nearly 70% as at the end of 2013.

13.13 FE is a wholly owned subsidiary of Bord Gas Eireann (BGE) although it has recently announced a sale with the preferred bidder consortium led by Centrica (see paragraph 2.11). BGE is a semi state-owned Irish Gas company. FE has no external debt. It is currently funded through intra-group equity and debt. The debt instruments of BGE are not necessarily reflective of the rates that FE may be able to achieve if it was a stand-alone company or privately owned.

13.14 The impact of these differences is discussed in the section on financial modelling assumptions below.

13.15 To assess financeability we consider a range of indicators but, in line with other UK regulators and the rating agencies we consider that the principle indicators are:

- Gearing (defined as net debt: TRV); and
- PMICR, post maintenance interest coverage ratio, defined as EBITDA (adjusted for issues such as under recoveries, deferred revenue and cash taxes) less regulatory depreciation all divided by cash interest.

13.16 There are three large and reputable credit rating agencies. We reproduce below two of the rating agencies' assessment of these key metrics; the third credit rating agency is Standard & Poor's.

Table 85 – Key financial metrics and credit rating

Metric	Fitch		Moody's	
	A	BBB	A	Baa
Gearing	60%	> 70%	45 - 60%	60 - 75%
PMICR	1.75x	1.5x	2.0 - 4.0x	1.4 - 2.0x

Source: Competition Commission provisional determination for NIE.

13.17 In addition, the Competition Commission's recent provisional determination for Northern Ireland Electricity[44] provided the following estimates specifically for the requirements for BBB+ (Fitch) or Baa1 (Moody's). These are based on the water sector (Moody's) and electricity DNOs (Fitch).

Table 86 – Key financial metrics and credit rating

Metric	Fitch	Moody's
	BBB+	Baa1
Gearing	60 - 75%	68 - 75%
PMICR	1.6 - 1.9x	1.4 - 1.6x

Source: Ofgem consultation on strategy for the RIIO T1 and GD1; annex discussing financial issues.

13.18 PNGL has a licence condition to maintain an investment grade rating. An investment grade credit rating is a rating of BBB- or above (Fitch or Standard & Poor's) or Baa3 (Moody's). We are not prescriptive on which credit rating agency is used by PNGL.

13.19 However, to ensure adequate "headroom" to allow for unforeseen events we would expect PNGL to target a credit rating of at least BBB. Consequently our financeability modelling ensures financial indicators will give a credit rating of BBB or above. Although FE does not have such a licence condition we would nevertheless target a similar credit rating. This is consistent with the targets used by Ofgem to determine financeability for energy networks.

13.20 Consequently in our financeability analysis we have targeted a credit rating of BBB (Fitch) equivalent to Baa2 (Moody's). This is equivalent to Moody's current rating of PNGL.

13.21 Financeability analysis inevitably involves an element of judgement. Moody's, for example, has historically had a favourable view of the UK regulatory environment.

[44] http://www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/131112_main_report.pdf

For example Moody's recent credit research note on PNGL's bond this summer[45] stated that the PNGL bond rating is based on the fundamental business risk of PNG including "the regulatory framework for gas distribution operators in Northern Ireland which, while having a shorter track record for consistent decision making, broadly follows that of Great Britain".

13.22 In such an environment, companies have been able to maintain credit ratings even when key financial metrics have fallen outside the ranges set for the specified credit rating.

13.23 Consequently we adopt a similar approach and do not expect companies to necessarily pass all ratios in all years. More important is the trend in the ratios and confirmation from the financial modelling that any short term dip in a ratio will reverse.

13.24 Whilst we believe that a PMICR of 1.4x should still enable companies to achieve a BBB rating, we have adopted a more prudent target that we have used for key financial metrics, based on table 86 above, of a PMICR of 1.5x or higher. In addition we target a gearing of 70% or lower. In practice, these metrics are probably adequate enough for GDNs to achieve a BBB+/Baa1 rating.

13.25 This also provides headroom over the bond covenants in PNGL's existing 5.5% bond described earlier and due for repayment in 2017 which require gearing of 77.5% or less, and a PMICR of 1.4x or better for dividend lock-up.

13.26 Whilst we have carefully considered the impact in 2014 to 2016 we have also considered the longer term ability of PNGL and FE to finance their activities. And whilst we will be repeating this exercise with updated data for the next price control in 2017, we feel it is important to examine a longer time period now, and so have carried out relevant calculations through to the end of the recovery periods for each GDN.

Financial Modelling Assumptions

13.27 To undertake our financial modelling it was clearly essential to determine the initial parameters for each company. We have developed a model consistent with this final determination including TRV's and projected capex, opex and volumes.

13.28 It is also worth noting that FE's under-recoveries will be over £20m at the end of 2013. This is effectively an IOU from customers to FE that it can draw down on by increasing tariffs above determined values. We have not taken account of the opportunity to utilise these under-recoveries in our modelling but these represent a further way for FE to mitigate any cost or revenue shocks.

13.29 A critical issue was to determine the opening gearing to use within the model. As noted above, PNGL's gearing has varied between around 55% and 70% this year. It is not for the regulator to dictate the level of gearing and the amount of dividends paid; these are decisions for management. We regulate the company at a more macro level via the credit rating requirements and the ring fencing arrangements enshrined within the licence.

13.30 It would be inappropriate to assume an initial gearing or interest rate for our financing modelling purposes based on the position for either of the GDNs at a point in time as the results would vary widely, for example for PNGL on whether we used the gearing before or after its £90m dividend payment this year. For FE we would have to use

[45] Moody's Investors service Issuer Comment 5 August 2013.

assumptions on interest rates that would no longer hold if FE was sold to a private company.

13.31 Consequently we have undertaken modelling of the GDNs on a "stand-alone" basis, that is irrespective of ownership or the way that the companies are managed by their owners. We have adopted a "pro forma" approach as does Ofgem in its modelling. We believe it is appropriate to use the same assumptions for both PNGL and FE as the companies would be broadly similar if operated on a stand-alone basis. As noted earlier, the current ownership arrangements should not impact on the assessment of financeability.

13.32 We have assumed an initial position of **65%** gearing for each company. This is consistent with Ofgem's assumption when it set the allowed cost of capital for GDNs and electricity DNOs in its recent price controls.

13.33 For inflation, the Bank of England's November 2013 report[46] has projected CPI inflation for 2015 and 2016 at 1.9%; this compares to the Government medium term target of 2% CPI.

13.34 However, Northern Ireland GDN regulation is based on RPI and accordingly the CPI forecast needs to be adjusted to an RPI forecast. The Bank of England, however, no longer publishes RPI forecasts.

13.35 In November 2011, the Office for Budget Responsibility published "Working paper no. 2 – The long-run difference between RPI and CPI inflation"[47]. This concludes that the difference between RPI and CPI is between 1.3% and 1.5%. As our financial model is a long term forecast we have used a consistent assumption for RPI. Accordingly in our base case model we have assumed CPI at 1.9% and the CPI/RPI differential at 1.4% to give an annual RPI assumption of **3.3%.** Although short term projections differ slightly, we have used the same RPI assumption for each year of the model.

13.36 We have assessed the evidence on interest rates. PNGL's bonds are currently trading on a redemption yield of just 3% as shown in the graph earlier in this section. However, we have used a substantially higher figure to be more consistent with current regulatory allowances for real debt costs. Accordingly, we have used a figure of **6.2% nominal** for interest rates for modelling purposes. This is conservatively above the 5.5% coupon on PNGL's bond.

13.37 In our draft determination we confirmed that we would allow a pre-tax real cost of capital of 7.5% for GD14 in line with the licences of PNGL and FE. However, we noted that this cost of capital is only set in the licences until 31 December 2016 and that, for modelling purposes only we would use an assumed cost of capital from 1 January 2017 of 4.83% real pre-tax. This takes into account recent UK regulatory precedents, for example it is in line with the assumption used by Ofgem in its recent determination for the UK gas distribution networks. Additionally, we note that the Competition Commission in its provisional determination in November 2013 for Northern Ireland Electricity[48] has proposed a cost of capital equivalent to a pre-tax 4.7%. We also note the comments of PNGL and FE in their response to the draft determination suggesting that the cost of capital should be higher than 4.83% from 2017. We address these comments in our response to the submissions received by respondents to the draft determination consultation. We have not, however, changed our cost of capital modelling assumption from 2017 and accordingly in our

[46] http://www.bankofengland.co.uk/publications/Pages/inflationreport/2013/ir1304.aspx
[47] http://cdn.budgetresponsibility.independent.gov.uk/Working-paper-No2-The-long-run-difference-between-RPI-and-CPI-inflation.pdf
[48] http://www.competition-commission.org.uk/assets/competitioncommission/docs/2013/northern-ireland-electricity-price-determination/131112_main_report.pdf

financeability model we have used a cost of capital of **4.83%**. More details are provided in our discussion on WACC in chapter 12.

13.38 If a GDN needed to conserve cash in the event of unforeseen cost or revenue shocks, an immediate, straightforward method would be to reduce dividend payments. Accordingly, the model has adopted some constraints on dividend payments depending on the ability of the company to finance dividends; these are described below. We would reiterate that we are not prescriptive on dividend policy and it would be for the GDN to determine dividend payments and to maintain an investment grade credit rating.

13.39 Our 4.83% WACC assumption post 2016 suggests a cost of equity of 6.5-7%. In our model we have allowed for an annual dividend of **9%** (2013-2015) and **7%** (2016 onwards) of the initial equity assumed in our pro-forma modelling of the regulated entity (that is 35% of the opening TRV), growing annually in line with RPI.

13.40 Our financial model suggested that there will be a sharp decline in PMICR in 2017 (from a high level). This is because the move in 2017 to a lower modelled WACC results in a sharp reduction in the profile adjustment which increases the amount of opex capitalised and hence reduces revenue from that in 2016. Accordingly we have included a restriction in our model on dividends before 2017. We have imposed a further restriction that dividends are not paid beyond a level that would reduce PMICR below 1.5x in that year.

13.41 In the event that modelled dividend is unpaid, for example between 2014 and 2016, the unpaid dividend is rolled forward, increased by the allowed WACC and the forecast RPI. This ensures that the GDN can still receive its full allowed return on equity.

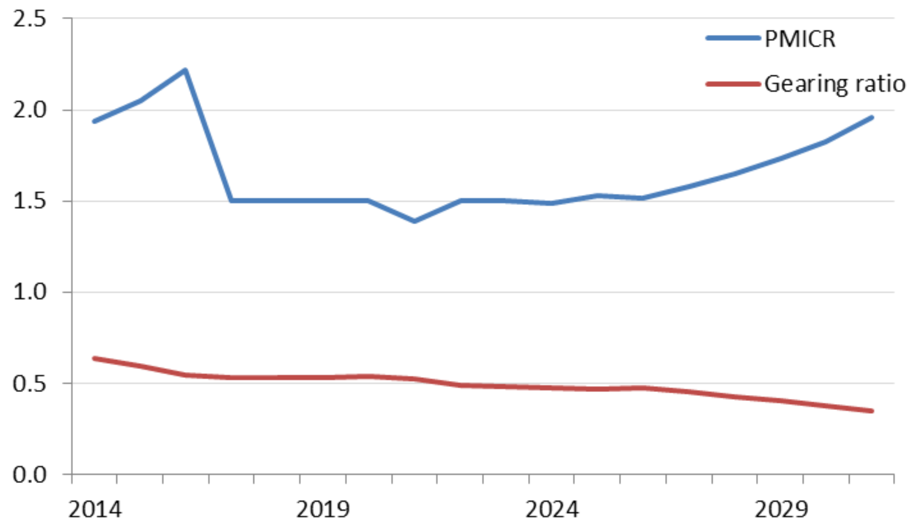
13.42 It should be noted that the targets for financial indicators and the financial modelling assumptions adopted relate to GD14 and should not be seen as setting any precedent for future review.

Central Case Projections

PNGL

13.43 Under our central case estimates as described in the section above the financial model projects the following profile for gearing and the PMICR.

Figure 17 – PNGL Key Financial Indicators: Central Case



Source: The Utility Regulator

13.44 Gearing declines steadily from the 65% assumed at the start of 2014.

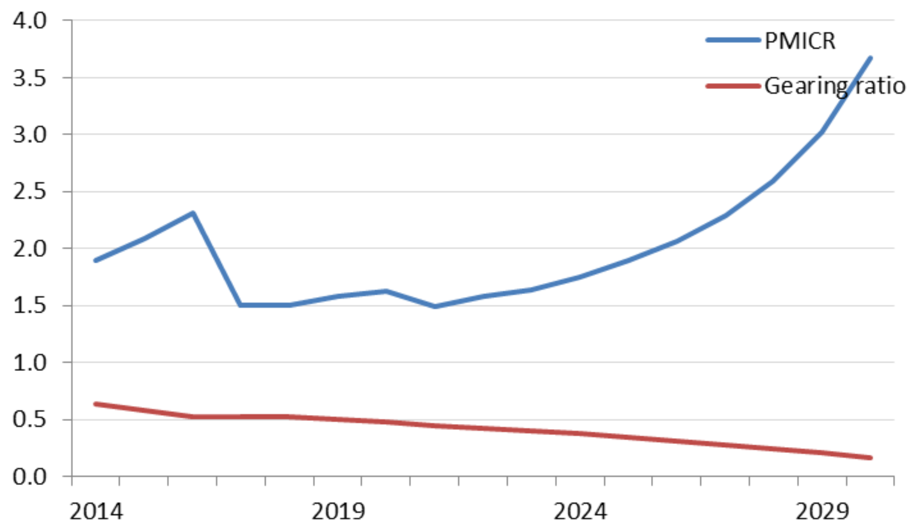
13.45 PMICR starts at a healthy 1.93x (due to the relatively high cost of capital of 7.5%). In 2017, PMICR dips to 1.5x as the cost of capital in our model drops to 4.83%. It remains at 1.5x, only dipping briefly to 1.39x in 2021 as PNGL starts paying tax. It rises back to 1.5x and from 2026 increases steadily. Although there are some dividend restrictions early on, the full accumulated dividend (with any unpaid dividend increased by RPI and WACC) is paid from 2022 onwards.

13.46 Note that we have modelled the full revenue recovery period through to the end of the licence, however for ease of display we have not included the full recovery period in the graph as the increasing PMICR would result in a smaller scale on the Y-axis.

FE

13.47 Under our central case estimates as described in the section above the financial model projects the following profile for gearing and the PMICR.

Figure 18 – FE Key Financial Indicators: Central Case



Source: The Utility Regulator

13.48 Gearing declines steadily from the 65% assumed at the start of 2014.

13.49 PMICR starts at a healthy 1.9x (due to the relatively high cost of capital of 7.5%). It stays at 1.5x or above throughout the licence period. Although there are some dividend restrictions early on, the full accumulated dividend (with any unpaid dividend increased by RPI and WACC) is paid from 2022 onwards.

Conclusions under the Central Case

13.50 Our analysis shows that both PNGL and FE will more than maintain a BBB rating as gearing drops markedly and PMICR is at or above 1.5x in nearly all years. Indeed table 86 above suggests that both GDNs would be rated BBB+/Baa1 or better. We are therefore content that the businesses are both robustly financeable in the base case under our final decisions.

Modelling Downside Scenarios

13.51 However, it is also important to assess whether the companies are able to withstand cost or revenue shocks. The financial model provides a basis for modelling alternative outturn scenarios.

13.52 The regulatory regime provides for some risk sharing – at periodic reviews, the price control is reset to take into account new information. This means that the company's exposure to unanticipated levels of costs or demand is limited and that, in due course, customers share in the financial benefit or pain.

13.53 In general, the company will be exposed for a period of up to five years, being the default period of price controls specified in the licence. The current review, however, is for a rather shorter period of three years to the end of 2016. To understand the potential scale of impact on the company if outturns are worse than expected, we have conservatively assumed allowances are not reset in future price controls. In practice however, we would take into account a change in conditions and reflect those in future price controls. Additionally, tariffs would be reset at each review. Consequently the scenarios modelled represent very pessimistic outcomes.

13.54 Both FE and PNGL are exposed to unanticipated cost pressures so we have included a reasonably extreme scenario for each which assumes a 15 per cent increase in both operating and capital expenditure from determination in each year from 2014 onwards.

13.55 FE has a particular exposure to volume risk as its prices are fixed. Consequently for FE we have also modelled a sharp reduction in volumes from determination whereby volume growth is just 25% of the determination level.

13.56 PNGL has no material exposure to reductions in volume from final determination assumptions as their revenue cap simply means that they can charge higher tariffs. In PNGL12 the downside scenario included an assumption that connections were down 50%. We have modelled this scenario and there is no material change to financial ratios compared to the base case because the reduction in costs offsets any lower revenue. Consequently in the downside scenarios below we have only included a detailed description of the cost sensitivity for PNGL which, we believe, reflects the key risks faced by PNGL.

13.57 We consider that the risk of these outturn variances may be small. Both PNGL and FE have a very good record of performance against regulatory allowances. Average net efficiencies are set at 0.8% per year for opex and 0.7% per year for capex which is substantially lower than the 15% assumed over-expenditure. Furthermore, the link of a fair proportion of costs to incentive mechanisms also limits the impact of any unexpected cost increases.

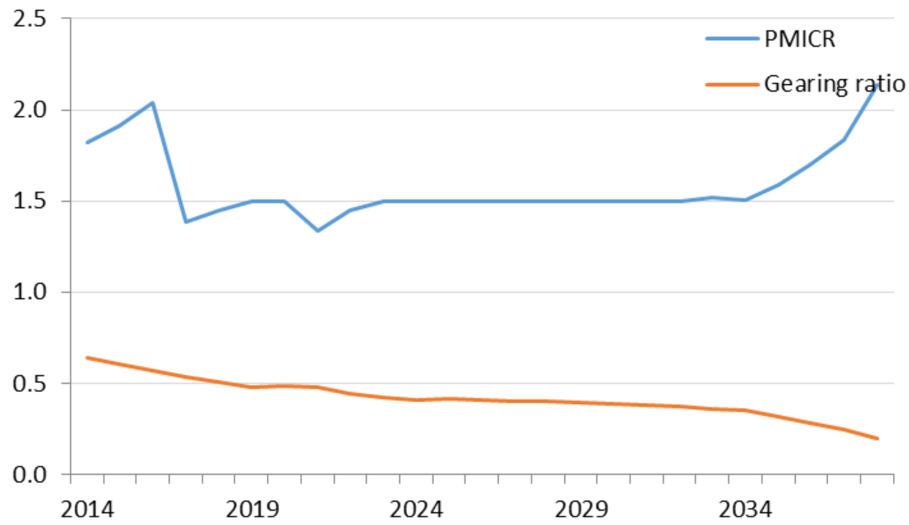
13.58 Similarly FE has a strong track record in outperforming volume allowances with an average outperformance against allowance in PC02 of 16% and hence our scenario of reducing volume growth by 75% whilst assuming the capex continues for the same level of connections represents a conservative downside.

Downside Scenarios Results

PNGL

13.59 The following chart summarises the results of the downside scenario for PNGL of 15% increase in opex and capex above determination.

Figure 19 – PNGL Key Financial Indicators: Cost downside



Source: The Utility Regulator

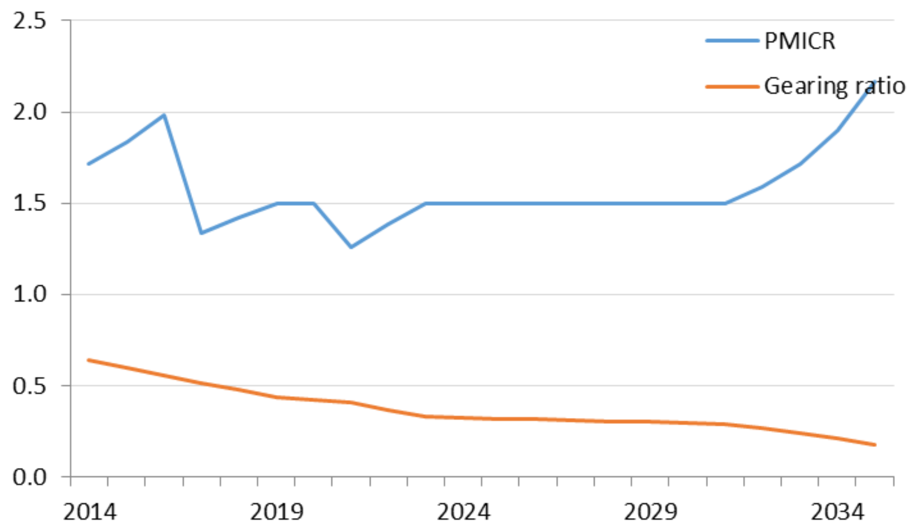
13.60 There is a dip in PMICR to 1.39x in 2017 and a recovery to 1.5x before a further dip to 1.34x in 2021 as tax payments kick in. Thereafter PMICR quickly recovers to 1.5x and it grows steadily from 2035. Gearing steadily declines from its starting point of 65%.

13.61 Both Moody's and Fitch have stated that they look at average metrics for a regulatory period rather than looking at specific years. Hence even with this onerous scenario, which assumes no resetting of allowances at future reviews, PNGL would be able to maintain at least a BBB rating as any dips below 1.5x cover are very brief. Some dividend payments are delayed but the full accumulated return on equity (inflation and WACC adjusted) is paid back to shareholders by 2033.

FE

13.62 The following chart summarises the results of the downside scenario for FE of 15% increase in opex and capex above determination.

Figure 20 – FE Key Financial Indicators: Cost downside



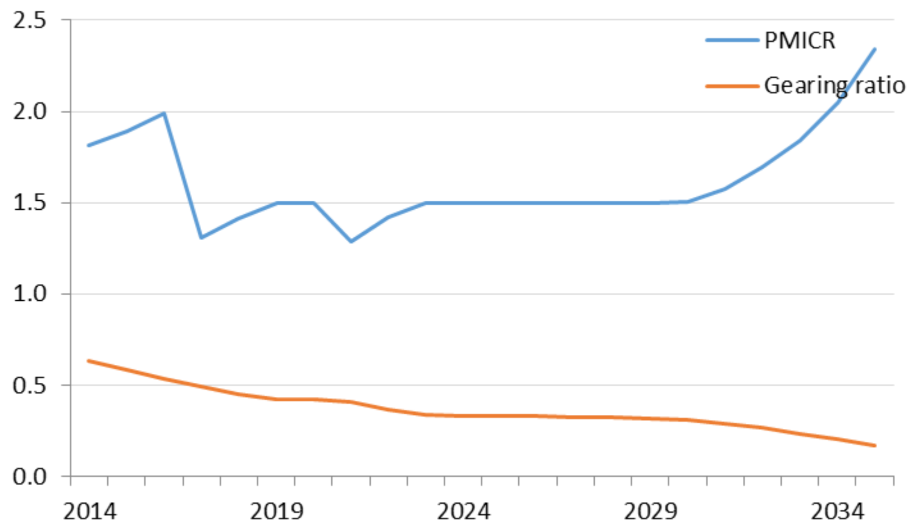
Source: The Utility Regulator

13.63 There is a dip in PMICR to 1.34x in 2017 and a dip to 1.26x in 2021 as tax payments kick in. In both cases recovery to 1.5x cover is swift. Thereafter PMICR stabilises and grows steadily from 2031. Gearing steadily declines from its starting point of 65%.

13.64 Hence even with this onerous scenario, which assumes no resetting of allowances at future reviews, FE would be able to maintain at least a BBB rating as any dips below 1.5x cover are very brief. Some dividend payments are delayed but the full accumulated return on equity (inflation and WACC adjusted) is paid back to shareholders by 2032.

13.65 The following chart summarises the results of the downside scenario for FE of a 75% decrease in the volume growth assumed in the final determination.

Figure 21 – FE Key Financial Indicators: Volume downside



Source: The Utility Regulator

13.66 There is a dip in PMICR to 1.31x in 2017 and a dip to 1.29x in 2021 as tax payments kick in. In both cases recovery to 1.5x cover is swift. Thereafter from 2023 PMICR stabilises at 1.5x and grows steadily from 2030. Gearing steadily declines from its starting point of 65%.

13.67 This downside scenario is similar to the previous one and similarly demonstrates that FE would be able to maintain at least a BBB rating as any dips below 1.5x cover are very brief. Some dividend payments are delayed but the full accumulated return on equity (inflation and WACC adjusted) is paid back to shareholders by 2030.

13.68 As noted earlier, in the event of any downside shocks, FE could utilise some of its £20m under-recoveries to mitigate the financial impact.

Overall Assessment of Financeability

13.69 Since our draft determination, we have used our financial model to undertake detailed analysis of PNGL and FE.

13.70 Under the central case scenario the PMICR is around 2x for both PNGL and FE for 2014 to 2016 which demonstrates a very strong credit rating. Beyond 2017, the PMICR remains around 1.5x and grows towards the end of the licence period thus demonstrating a robust financial settlement. Additionally, gearing drops steadily form the initial assumed 65%. As a consequence both companies will be able to maintain or exceed a BBB credit rating.

13.71 The results of our downside scenario modelling demonstrate that there is no significant pressure on the ratios for any of our three scenarios. A deferral of dividend payments in the event of unexpected cost pressures (or volume shortfalls in the case of FE) enable both companies to remain substantially above 1.5x PMICR during GD14 and at or close to 1.5x PMICR thereafter whilst gearing continues to decline.

13.72 Fundamentally the underlying financial resilience in the short, medium and longer term means that both businesses are inherently robust. We remain satisfied that our final decisions leave the companies on financially sustainable trajectories.

13.73 Consequently, with reference to our statutory duties, the allowed revenues we have determined are sufficient to ensure that both PNGL and FE can finance the activities which are the subject of obligations placed on them under the legislation. We are therefore content that both businesses are and continue to be financeable under our final decisions.

14 DRAFT GD14 OUTPUTS

Update from Draft Determination

14.1 We have considered efficiency effects resulting from the move of the economic frontier and those resulting from catch-up with the economic frontier. In analysing the frontier shift, we have taken account of real price effects and productivity improvements with a resulting reduction in our net annual efficiency targets.

14.2 We have made minor modifications to the designated parameters table in line with PNGL's suggestion.

Introduction

14.3 The previous chapters have provided our determination of the revenue "building blocks" for GD14, namely:

- opex;
- capex;
- volumes;
- opening asset values;
- allowed return on assets; and
- depreciation.

14.4 This chapter provides the outputs from our review, the allowed revenues. It commences with the definitions of specific parameters defined in the licence and our determination of annual efficiency targets.

Designated Parameters

14.5 Both PNGL and FE have a list of "designated parameters" defined in their licences that are set at each review period. This section sets out our views on the values of these designated parameters to apply from 1 January 2014 and the rationale behind our views.

PNGL

14.6 PNGL has five designated parameters and the values for these for GD14 are shown below.

Table 87 – Designated parameters, PNGL

Designated parameter	Description	PC03 Determined 2007-11	PNGL12 Determined 2012-13	Discussion	GD14 Determined 2014-16
r_t	Allowed pre-tax rate of return	0.075	0.075	The licence specifies that this parameter should remain at 7.5% until the end of 2016	0.075
n	Formula year preceding first determination year	2006	2011		2013
m	The formula year that was n for the preceding review year	2001	2006		2011
q	Final year for licensee to provide best available values	2046	2046	As set in the licence	2046
RPI	Indexation base			Prices expressed as September 2012 prices	

Source: The Utility Regulator

FE

14.7 FE has 15 designated parameters defined in its licence, which we are required to set as part of the price control.

14.8 The table below provides the values for FE designated parameters to apply for GD14. Two particular issues worthy of further discussion are rolling incentive mechanisms and the return on under-recoveries.

Rolling incentive mechanisms

14.9 Rolling incentive mechanisms enable licensees to retain efficiency savings for a period of years and then pass the benefits through to customers. The benefits are two-fold. Firstly a rolling mechanism can provide stronger incentives on licensees, for example we are minded to allow licensees to retain any capex efficiency savings for five years rather than, say, remove all efficiencies in GD17. Secondly, the benefits will be passed to customers after five years; a five year period approximately equalises the benefits between licensees and customers. We confirm that we will "switch on" the capex rolling incentive mechanism for FE for GD14 as flagged in the draft determination. This would remove over or underspends after five years compared to the allowance as adjusted by the retrospective mechanism.

14.10 We have not switched on the opex rolling incentive mechanism; we would note that a large proportion of opex is subject to the retrospective mechanism. We plan to consider opex rollers as part of GD17.

Return on under-recoveries

14.11 FE currently receives the full 7.5% cost of capital return on under-recoveries. We believe that this is providing an inappropriate incentive on FE to set tariffs below allowed tariffs and hence increase under-recoveries.

14.12 Consequently, we have considered options to address this in section 10. As part of dealing with under recoveries we are setting the designated parameter α_t at 0.4 which will allow firmus to significantly reduce this amount before GD17.

Table 88 – Designated parameters, FE

Designated parameter	Description	PCR02 Determined 2009-13	Discussion	GD14 Determined 2014-16
r_t	Allowed pre-tax rate of return	**0.075**	The licence specifies that this parameter should remain at 7.5% until the end of 2016	**0.075**
N	Formula year preceding first determination year	**2008**		**2013**
f_t	A parameter used to adjust the return to compensate for rate of return applied at end of year	**0.5**	Reasonable for Firmus to be allowed half year recovery as on average cash flows are mid-year	**0.5**
Q	Final year for licensee to provide best available values	**2035**		**2035**
RPI	Indexation base		Prices expressed as average 2012 prices	
w	The number of years for which the operator can retain opex and capex savings under the opex and capex rolling mechanisms	**0**	We have determined to establish a capex roller for this review to incentivise capex savings. A 5 year roller approximately equalises benefits between licensee and customers	**5**
g	A switch for the opex rolling incentive	**0**	We have determined not to switch on the opex rolling incentive (see above)	**0**
h	A switch for the capex rolling incentive	**0**	We have determined to switch on the capex rolling incentive (see above)	**1**
d	A switch for the depreciation component of the capex rolling incentive	**0**		**1**
l	The average asset life of the capex savings	**0**	The average regulatory life of capex in PCR02 through to 2035 was 33	**33**
δ_t	A factor that can be used to reduce the extent that an over-recovery of revenue in one conveyance category can offset an under-recovery of revenue in another conveyance category	**0**	There is no change in this parameter.	**0**
$x_{u,t}$	A factor that can be used to adjust the rate of return allowed on under-recoveries	**0**	The licence sets this to zero until 2034. As noted above we are considering increasing this factor but not until 2017	**0**
$x_{o,t}$	A factor that can be used to adjust the rate of return allowed on over-recoveries	**0**	We will consider setting this with $x_{u,t}$ in GD17	**0**
α_t	The maximum amount that actual revenue (sum of volume times tariff for each conveyance category) can exceed allowed revenue	**0.1**	To enable Firmus to reduce its under-recoveries we are increasing the value of this parameter.	**0.4**

Source: The Utility Regulator

Overview

14.13 When setting an efficiency target, two effects need to be considered: move of the frontier and move towards the frontier.

14.14 The move of the frontier – or frontier shift – describes the efficiency gains resulting from companies becoming more efficient over time, e.g. through technological progress. The frontier shift in real terms can be calculated as follows:

Frontier shift in real terms = input price inflation minus

forecast RPI (measured inflation) minus

productivity increase

14.15 The move towards the frontier describes the efficiency gains a company can achieve through catching-up with the economic frontier.

Frontier Shift

14.16 As part of the frontier shift calculation, the impact of input price inflation needs to be established. As prices for different types of inputs can develop in different ways, it is good practice to distinguish between different cost categories. In our analysis, we have differentiated between the cost categories shown in Table 89.

Table 89 – Cost Categories and Weightings for Efficiency Analysis

Cost Category	Opex	Capex
Labour (direct and contracted)	52%	56%
Materials	6%	19%
Equipment/ Plant	1%	4%
Other	41%	21%

Source: The Utility Regulator

14.17 We have aligned our approach for cost category differentiation with the one used by Ofgem in their RIIO GD1 price control[49]. Like Ofgem[50], we have decided not to differentiate in our forecasts for input price inflation between direct and contract labour as we do not want to set differential real wage assumptions based on network companies preferred operational/ contract decisions. Also, in line with the Competition Commission provisional determination on the NIE RP5 price control[51], we have not differentiated between "specialist" and "general" labour. We have considered additional cost categories, such as IT, used by us in determining efficiencies for other price controls[52]. However, based on the data available from the

[49] See Ofgem: RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, 27 July 2012, p. 6 and Ofgem RIIO-T1/GD1: Final Decision – Real price effects and ongoing efficiency appendix, 17 December 2012.
[50] See Ofgem: RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, 27 July 2012, p.10 and Ofgem RIIO-T1/GD1: Final Decision – Real price effects and ongoing efficiency appendix, 17 December 2012.
[51] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-8 to 11-9.
[52] See e.g. The Utility Regulator: NIE T&D RP5 Price Control, Appendix I: Real Price Effects, published 23 October 2012.

PNGL and FE business cases, we have concluded that this is not a material cost category. That said, we intend to re-consider a further differentiation of the cost categories as part of future price controls, where appropriate, in order to refine the basis on which we determine efficiency targets.

14.18 We have based the weighting of the different cost categories on the notional structure of a GDN used by Ofgem in their RIIO GD1 price control[53].We consider that these weights should be relevant for GDNs operating in Northern Ireland as well, without the need for regional adjustments. We note that the Competition Commission, in their provisional determination on the NIE RP5 price control[54], has suggested the use of company-specific weightings rather than weightings for a notional company. This is something we intend to consider for future price controls.

14.19 In line with the approach taken as part of a number of other recent price controls[55], we have based our forecast for the development of opex and capex labour costs on the OBR (Office for Budget Responsibility) Economic and Fiscal Outlook data for average weekly earnings. Table 90 shows the OBR forecast for the Labour Market,

14.20 Table 91 our forecast for labour costs also uses the OBR set of forecasts.

Table 90 – Economic and Fiscal Outlook – Labour Market

Labour Market	Percentage change on a year earlier, unlesss otherwise stated						
	Outturn		Forecast				
	2011	2012	2013	2014	2015	2016	2017
Employment (millions)	29.2	29.5	29.8	29.9	30.1	30.3	30.5
Wages and salaries	2.7	2.8	2.4	3.1	4.3	4.8	4.8
Average earnings (wages and salaries divided by employees)	2.3	2.1	1.4	2.7	3.6	4.0	4.0
ILO unemployment (%rate)	8.1	7.9	7.9	8.0	7.9	7.4	6.9
Claimant count (millions)	1.5	1.6	1.6	1.6	1.6	1.5	1.4

Source: OBR: Economic and Fiscal Outlook, March 2013

Table 91 – Labour Cost Forecast

Percentage change on year earlier	2012	2013	2014	2015	2016
Labour (direct and contracted)	2.1%	1.4%	2.7%	3.6%	4.0%

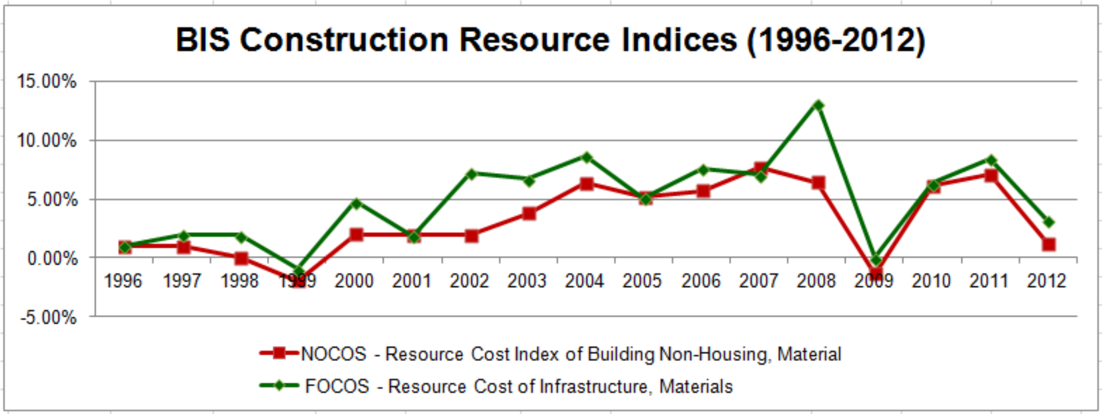
Source: The Utility Regulator

14.21 In line with the approach taken as part of a number of other recent price controls[56], we have based our forecast for the development of opex and capex materials costs on the BIS (Department for Business, Innovation and Skills) Construction Resource Cost Indices NOCOS (Resource Cost Index for Building Non-Housing), Materials

[53] See Ofgem: RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, 27 July 2012, p. 6 and Ofgem RIIO-T1/GD1: Final Decision – Real price effects and ongoing efficiency appendix, 17 December 2012.
[54] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-11.
[55] See e.g. First Economics: Real Price Effects 2013/2014 to 2022/2023 prepared for WPD, 14 January 2013, p. 6 and Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-16.
[56] See e.g. First Economics: Real Price Effects 2013/2014 to 2022/2023 prepared for WPD, 14 January 2013, p.8-9 and Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-9 to 11-11.

Series and FOCOS (Resource Cost Index for Infrastructure), Materials Series. Figure 22 provides an overview over the historic annual price change of these indices. For the period 1996 to 2012; the Resource Cost Index for Building Non-Housing shows a long-term average annual price increase of 3.3%, the Resource Cost Index for Infrastructure of 5.1%. In line with the Competition Commission provisional determination on the NIE RP5 price control[57], we have used the unweighted average of these long-term average price increases as the basis for our forecast, without gradual adjustments from the level of these indices seen in 2012/2013 towards the long-term average. Table 92 provides an overview of our forecast for materials costs.

Figure 22 - BIS Construction Resource Indices – Annual Price Change



Source: BIS, September 2013

Table 92 – Forecast of Materials Costs

Percentage change on year earlier	2012	2013	2014	2015	2016
Materials Opex	2.2%	4.2%	4.2%	4.2%	4.2%
Materials Capex	2.2%	4.2%	4.2%	4.2%	4.2%

Source: The Utility Regulator

14.22 In line with the Competition Commission provisional determination on the NIE RP5 price control[58], we have based our forecast of opex and capex plant and equipment costs on the ONS PPI (Producer Price Inflation) Machinery and equipment output index and the BCIS Plant and Road Vehicles Index (Series 90/2). Figure 23 provides an overview over the historic annual price change of these indices. For the period 1996 to 2012; the ONS PPI Machinery and equipment output Index shows a long-term average annual price increase of 1.8%, the BCIS Plant and Road Vehicles Index of 2.9%. In line with the Competition Commission provisional determination on the NIE RP5 price control[59], we have used the unweighted average of these long-term average price increases as the basis for our forecast, without gradual adjustments from the level of these indices seen in 2012/2013 towards the long-term average. Table 93 provides an overview of our forecast for plant and equipment costs.

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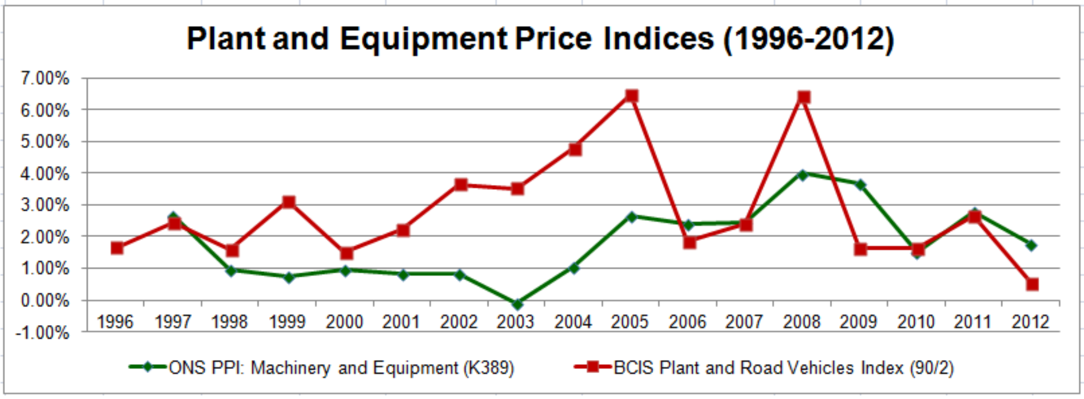
[57] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-9 to 11-11.
[58] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-9 to 11-11.
[59] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-9 to 11-11.

Figure 23 – Plant and Equipment Price Indices– Annual Price Change



Source: ONS (17 October 2013) and BCIS (22 July 2013)

Table 93 – Forecast of Plant and Equipment Costs

Percentage change on year earlier	2012	2013	2014	2015	2016
Plant and Equipment Opex	1.1%	2.4%	2.4%	2.4%	2.4%
Plant and Equipment Capex	1.1%	2.4%	2.4%	2.4%	2.4%

Source: The Utility Regulator

14.23 In line with regulatory practice[60], we have assumed that the costs subsumed in the "Other" cost category inflate with RPI.

14.24 In line with the approach taken in a number of other recent price controls[61], we have based our RPI forecast on OBR (Office for Budget Responsibility) Economic and Fiscal Outlook data for RPI. Table 94 shows the OBR forecast for inflation, Table 95 our forecast for RPI.

[60] See e.g. Ofgem: RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix, 27 July 2012, p. 15 and Ofgem RIIO-T1/GD1: Final Decision – Real price effects and ongoing efficiency appendix, 17 December 2012 or Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-10.

[61] See e.g. First Economics: Real Price Effects 2013/2014 to 2022/2023 prepared for WPD, 14 January 2013, p.14-16 and Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-8.

Table 94 – Economic and Fiscal Outlook –Inflation

Inflation	Percentage change on a year earlier, unlesss otherwise stated					
	Outturn	Forecast				
	2012	2013	2014	2015	2016	2017
CPI	2.8	2.8	2.4	2.1	2.0	2.0
RPI	3.2	3.2	2.8	3.2	3.6	3.9
GDP deflator at market prices	1.3	2.1	2.0	1.8	1.8	1.7

Source: OBR: Economic and Fiscal Outlook, March 2013

Table 95 – RPI Forecast

Percentage change on year earlier	2012	2013	2014	2015	2016
RPI	3.2%	3.2%	2.8%	3.2%	3.6%

Source: The Utility Regulator

14.25 Based on the considerations and assumptions outlined above, the input price inflation can be determined by calculating the weighted average of the input price increases for the different cost categories: Table 96 and Table 97 summarise our forecast for the input price for opex and capex respectively.

Table 96 –Input Price Forecast Opex

Percentage change on year earlier	Weight	2012	2013	2014	2015	2016
Labour (direct and contracted)	52%	2.1%	1.4%	2.7%	3.6%	4.0%
Materials	6%	2.2%	4.2%	4.2%	4.2%	4.2%
Equipment/ Plant	1%	1.1%	2.4%	2.4%	2.4%	2.4%
Other Inputs (in line with RPI)	41%	3.2%	3.2%	2.8%	3.2%	3.6%
Input Price Increase (nominal)		2.5%	2.3%	2.8%	3.5%	3.8%
RPI		3.2%	3.2%	2.8%	3.2%	3.6%
Input Price Increase (real)		-0.7%	-0.9%	0.0%	0.3%	0.2%

Source: The Utility Regulator

Table 97 – Input Price Forecast Capex

Percentage change on year earlier	Weight	2012	2013	2014	2015	2016
Labour (direct and contracted)	56%	2.1%	1.4%	2.7%	3.6%	4.0%
Materials	19%	2.2%	4.2%	4.2%	4.2%	4.2%
Equipment/ Plant	4%	1.1%	2.4%	2.4%	2.4%	2.4%
Other Inputs (in line with RPI)	21%	3.2%	3.2%	2.8%	3.2%	3.6%
Input Price Increase (nominal)		2.3%	2.3%	3.0%	3.6%	3.9%
RPI		3.2%	3.2%	2.8%	3.2%	3.6%
Input Price Increase (real)		-0.9%	-0.9%	0.2%	0.4%	0.3%

Source: The Utility Regulator

14.26 Having considered the findings of the Competition Commission in its provisional determination on the NIE RP5 price control[62], we have assumed the average annual productivity increase to be 1% for both opex and capex. This is in line with recent productivity assumptions made in other price controls, as shown in Table 98. It is also

[62] See Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-2 to 11-6.

in line with the EU KLEMS data which, in line with Competition Commission analysis[63], could support a range of productivity estimates between 0.5% and 1.5%.

Table 98 – Opex and Capex productivity assumptions in other price control reviews

	%
Opex productivity	
UR—Water and sewerage	0.9
PPP Arbiter—underground infracos, central costs	0.7
PPP Arbiter—underground infracos, opex	0.9
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	1.0
ORR—Network Rail, opex	0.2
ORR—Network Rail, maint	0.7
Capex productivity	
PPP Arbiter—underground infracos	1.2
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	0.7
ORR—Network Rail	0.7

Source: UR, CC analysis.

Notes:
1. UR's PC13 Water and Sewerage determination relates to 2012 .
2. PPP Arbiter's decision for underground infrastructure companies (infracos) relates to 2010 Ofgem's decision for DNOs relates to 2009.
3. Ofgem's decision for Transmission and Gas Distribution relates to 2012.
4. ORR's decision for Network Rail relates to 2008.

Source: Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013, p. 11-3.

14.27 The Frontier Shift in real terms can be calculated by deducting the average annual productivity increase from the input price increase in real terms. Table 99 and Table 100 summarise the results for opex and capex respectively.

Table 99 – Frontier Shift in Real Terms Opex

Opex	2012	2013	2014	2015	2016	Average (2014-2016)
Input Price Increase (real)	-0.7%	-0.9%	0.0%	0.3%	0.2%	0.2%
Productivity Increase	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Fontier Shift (real)	-1.7%	-1.9%	-1.0%	-0.7%	-0.8%	-0.8%

Source: The Utility Regulator

Table 100 – Frontier Shift in Real Terms Capex

Capex	2012	2013	2014	2015	2016	Average (2014-2016)
Input Price Increase (real)	-0.9%	-0.9%	0.2%	0.4%	0.3%	0.3%
Productivity Increase	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Fontier Shift (real)	-1.9%	-1.9%	-0.8%	-0.6%	-0.7%	-0.7%

Source: The Utility Regulator

14.28 With 2011 being the base year of the capex data, we have applied both Real Price Effects and productivity increases for 2012 and 2013 to determine the starting position for the GD14 price control period. We have then applied both Real Price Effects and ongoing productivity increases for 2014 through to 2016 to determine the allowed post-efficiency capex allowances for each year of the price control period.

14.29 As the opex data used during the GD14 price control was based on a range of different base years, we have decided, on this occasion, to apply Real Price Effects

[63] See [Competition Commission: Northern Ireland Electricity Limited Price Determination, Provisional Determination, 8 November 2013](), p. 11-4 to 11-5.

and productivity increase from 2014 through to 2016 to determine the allowed post-efficiency opex allowances for each year of the price control period. We note, however, that for future price controls, we intend to establish a clear base year for both, capex and opex, and then apply Real Price Effects and productivity increases from the year following that base year, in a similar way as described above for the GD14 capex allowances.

14.30 In order to determine the post-efficiency opex (capex) allowances, we have applied the relevant compound Real Price Effect and ongoing productivity increase factors (calculated as detailed in paragraphs 14.28 and 14.29 above) for each year to the controllable pre-efficiency opex (capex) allowance to establish the controllable post-efficiency opex (capex) allowance. We have then added the uncontrollable opex (capex) to obtain the overall post-efficiency opex (capex) allowance.

14.31 We note that PNGL has commented that licence fees and rates should be considered to be uncontrollable opex items and should be excluded from the application of efficiency targets. Whilst we agree that licence fees are uncontrollable opex items, we do not agree that the same is the case for rates. We have therefore decided to consider all opex items other than licence fees and connection incentives to be controllable. Table 33 (at the end of chapter 5) and Table 54 (at the end of chapter 6) provide an overview of the breakdown of the PNGL and FE pre-efficiency opex allowances into controllable and uncontrollable opex.

14.32 We consider all capex items (including TMA) to be controllable; hence, the uncontrollable capex is £0 for each year of the price control.

14.33 Table 34 (at the end of chapter 5) and Table 55 (at the end of chapter 6) provide an overview of the controllable opex pre-efficiency, the controllable opex post-efficiency and the total opex post-efficiency for PNGL and FE respectively for each year of the price control period. Table 67 (at the end of chapter 7) and Table 78 (at the end of chapter 8) provide an overview of the controllable capex pre-efficiency, the controllable capex post-efficiency and the total capex post-efficiency for PNGL and FE respectively for each year of the price control period.

Catch-up with the Frontier

14.34 In order to establish the efficiency gains a company can achieve by moving closer to the economic frontier, it is necessary to establish the gap that exists between the performance of the company and the frontier. The quality of any such analysis will depend on the availability and quality of comparator data, as well as on consideration of any special factors and atypical events that might be relevant.

14.35 As part of the current price control, we have chosen not to apply a separate catch-up efficiency challenge. In other words, we have implicitly assumed in the absence of any evidence to the contrary that, with some specific adjustments to our allowances as a result of benchmarking analysis in selected areas, the GDNs allowance are reflective of a company at the frontier.

14.36 We intend to reconsider as part of our future price controls options for further refinement of our approach to establishing the gap between the GDN performance and the performance of a company operating at the frontier, and to setting related catch-up efficiency targets, where appropriate.

14.37 We note that PNGL and FE have both commented that the application of efficiency factors to reflect real term frontier shifts would result in the double-counting of efficiencies. We do not agree with this view. Both, efficient and inefficient companies can be expected to become more efficient over time, e.g. through technological progress, during periods where the productivity increases outweigh the anticipated

Real Price Effects that would face an efficient company. This is reflected in the real term frontier shift efficiency target.

Allowed Revenues, PNGL

14.38 We have used the regulatory model to assess the revenues that we will grant over this control period. In the table below we set out a summary of the key input components to the model, and the resulting allowed revenues it has calculated[64].

Table 101 – Regulatory Model Inputs (Pre Efficiency) and Resulting Allowed Revenues for PNGL, £m

Component	PNGL Submission				Final Determination				Difference	Difference, %
	2014	2015	2016	Total	2014	2015	2016	Total	Total	Total
Opex allowance	16.5	17.0	16.8	**50.3**	13.7	14.0	14.2	**42.0**	**-8.3**	**-17%**
Capex allowance	13.6	13.7	13.5	**40.8**	12.7	13.0	12.9	**38.6**	**-2.2**	**-5%**
Total	**30.1**	**30.7**	**30.3**	**91.1**	**26.4**	**27.0**	**27.1**	**80.6**	**-10.5**	**-12%**
Cost of capital	**7.5% (7.5% post 2016)**				**7.5% (4.83% Post 2016)**					
Depreciation	**See discussion above.**				**As per PNGL submission for GD14.**					
The above allowances are fed into our regulatory model, which calculates a revenue requirement to ensure the company recovers the value of future as well as past investments, plus a return on this investment.										
Allowed revenues	58.1	60.0	61.8	179.9	44.6	46.3	48.0	138.9	-41.0	

Source: PNGL and the Utility Regulator

Impact on Consumer Bills, PNGL

14.39 The result of our decisions will see distribution charges fall from the 2013 CC determined charge levels. This is mainly a result of about a 2% increase in targeted volumes compared to the CC determined model from 2014 to 2046 and the reduction in the rate of return within the modelling of tariffs post 2016.

14.40 The determined charge in relation to a domestic consumer equates to 37.65 pence per therm, when compared to the 2013 domestic tariff determined by the Competition Commission of 43.37[65] pence per therm (2012 prices), this gives a saving of 5.72 pence per therm.

14.41 The average consumption of a domestic consumer is assessed as 410 therms per annum for the purposes of this price control giving a total annual bill of £574[66], in

[64] This table sets out allowances for the control period only i.e. 2014, 2015 and 2016. However, it should be noted that as part of every price control we model costs and revenues through to 2046 (the end of PNGL's licence recovery period). This is necessary since the PNGL business model requires the deferral of some of its entitled revenues to be recovered at some point in the future (known as the Profile Adjustment). This helps keep conveyance charges lower now which in turn encourages the continued growth of the gas market.

[65] This figure was determined by the competition commission based on a post 2016 rate of return of 5.87%.

[66] Based on the current Airtricity home energy tariff (Ex VAT) – effective 1st April 2013.

turn, this gives an average domestic consumer a saving of around £23 (or 4.1% of total bill) per annum.

14.42 For I&C customers, in particular larger burning consumers, the difference would be even higher.

14.43 Note that the impact on customer bills will only be fully realised in 2015 as 2014 distribution charges have already been set. Also the distribution charges contribute 35% to the total consumer bill and bills are also driven by other changes e.g. price of gas.

Allowed Revenues, FE

14.44 We have used the regulatory model to determine the prices that we will grant over this control period. In the table below we set out a summary of the key input components to the model, and the resulting allowed revenues.

Table 102 – Regulatory Model Inputs (Pre Efficiency) and Resulting Allowed Revenues for FE, £m

Component	FE Submission				Final Determination				Difference	Difference, %
	2014	2015	2016	Total	2014	2015	2016	Total	Total	Total
Opex allowance	8.3	8.5	8.9	25.7	5.4	5.6	5.8	16.8	-8.9	-35%
Capex allowance	15.1	12.9	11.2	39.1	11.6	9.8	8.9	30.2	-8.9	-23%
Total	23.4	21.4	20.1	64.8	17	15.4	14.7	47	-17.8	-27%
Cost of capital	7.5% (7.5% post 2016)				7.5% (4.83% Post 2016)					
Depreciation	See discussion above.				As per FE submission.					
The above allowances are fed into our regulatory model, which calculates a conveyance charge to ensure the company recovers the value of future as well as past investments, plus a return on this investment.										
Allowed revenues	21.6	22.9	23.6	68.1	17.8	18.4	18.8	55.0	-13.1	

Source: FE and the Utility Regulator

Impact on Consumer Bills, FE

14.45 The result of our decisions will see distribution charges fall from the previously determined tariff levels. This is as a result of a significant increase in the assessed volumes compared to those determined in PCR02 and the reduction in the rate of return within the modelling of tariffs post 2016.

14.46 The determined charge in relation to a domestic consumer equates to 39.14 pence per therm, when compared to our PCR02 determined cost of 51.33[67] pence per therm (£2012 as adjusted for RPI), this gives a saving of 12.19 pence per therm.

14.47 The average consumption of a domestic consumer is assessed as 410 therms per annum for the purposes of this price control giving a total annual bill of £567[68], in

[67] This figure was determined previously based on a post 2016 rate of return of 7.5%.

turn, this gives an average domestic consumer a saving of around £50 (or 8.8% of total bill) per annum.

14.48 For I&C customers, in particular larger burning consumers, the difference would be even higher.

14.49 The impact on actual bills will depend on FE's approach to under recovery. FE has substantial accumulated under-recoveries and as these unwind charges will be higher than in our determination. Also the distribution charges contribute 35% to the total consumer bill and bills are also driven by other changes e.g. price of gas.

[68] Based on the current firmus network home gas tariff – Effective 1st October 2013.

15 GD14 Uncertainty Mechanisms

Update from Draft Determination

15.1 We have updated for the approach taken in the capex and opex chapters and we have introduced a new retrospective mechanism linked to the environmental EU directive.

Introduction

15.2 We have included a number of mechanisms within this Determination to reduce the risk to GDNs or to incentivise them to deliver outputs consistently with our statutory duties as described at the start of chapter 3.

15.3 This chapter summarises these mechanisms and, where appropriate, references the sections of this document where the rationale and operation of the mechanisms are described in more detail.

15.4 The primary mechanism that we use is termed the "retrospective mechanism" as it will be effected in GD17 by retrospectively adjusting allowances based by differences between actual and allowed costs or outputs (such as connection activity).

15.5 Retrospective adjustments fall into one of three categories as set out in our determination, namely:

- Output based – we determine a unit price (Capex) or unit allowance (Opex). The value included in the cost base is the determined unit price/unit allowance x the forecast driver for that item e.g. connections/properties passed (Opex) or m per connection (Capex). Any difference in outputs (e.g. higher connections) between the determination and outturn will result in a retrospective adjustment at the time of GD17 (i.e. determined unit rate/unit allowance x actual driver output less determined unit rate/unit allowance x forecast driver output).
- Pass through – Any difference between the allowance in the determination and the actual costs incurred will result in a retrospective adjustment at the time of GD17.
- Ring fenced – Similar to pass through items but we will require a justification from the licence holder that the costs were necessarily and efficiently incurred otherwise the full amount may not be allowed.

15.6 The retrospective adjustments will also include the impact of the allowed cost of capital from the date of the difference in expenditure to the date that the retrospective adjustment is made.

15.7 We also discuss below the rolling incentive mechanism which will apply to GD14 for capex.

15.8 The determined unit rates applied in the uncertainty mechanism will be post efficiency.

Uncertainty Mechanism, PNGL

15.9 In PCR03, we determined the scope of the retrospective adjustments necessary to account for actual output performance versus determined values. The retrospective adjustments PCR03 determination was used in PNGL12 and remains similar for GD14.

15.10 For **Capex**, the items subject to retrospective adjustment are those shown in the table below.

Table 103 – PNGL capex uncertainty mechanism

Capex Item	Determination Basis
Traffic Management Act	Ring fenced
Pressure Reduction Stations	Output based on actual numbers installed
7 bar, 4 bar & Feeder Mains	Output based – linked to approved projects (none have been approved in GD14)
Other Mains: Existing Domestic and I&C	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 7.7 metres and determined unit rate. Additional incentive and penalties will apply as outlined in section 7.
Infill Mains: New Build Domestic	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 5.9 metres and determined unit rate.
Domestic/I&C Meters	Output based on connections and determined unit rates.
Domestic/I&C Services	Output based on connections and determined unit rates.
Capex over and under spend	We will retrospectively allow approved capex into the cost base at the time of the next review e.g. as a result of Energy Efficiency improvements.

Source: The Utility Regulator

15.11 For **Opex**, the items subject to retrospective adjustment are those shown in the table below.

Table 104 – PNGL opex uncertainty mechanism

Opex Item	Determination Basis
Rates	Output based on turnover as set out in PNGL opex section
Licence Fees	Pass through
Connections Incentive Mechanism (inclusive of sales/support staff and related overheads)	Output based on Owner Occupier connections (excluding assessed non-additional connections) and determined unit rates (as adjusted for over/under performance with respect to target owner occupier connections. This is outlined in PNGL opex section.

Source: The Utility Regulator

Uncertainty Mechanism, FE

15.12 PCR02 included a retrospective mechanism for FE and a similar mechanism has been applied in this price control.

15.13 For **Capex**, the items subject to retrospective adjustment are those shown in the table below.

Table 105 – FE capex uncertainty mechanism

Capex Item	Determination Basis
Traffic Management Act	Ring fenced
Pressure Reduction Stations	Output based on actual numbers installed
All Mains (4 Bar Mains, Feeder Mains, Infill Mains & Security of Supply)	Ring Fenced as set out in Section 8. We will determine on this once sufficient information has been received and our determination will clarify any retrospective issues.
Domestic/I&C Meters	Output based on connections and determined unit rates.
Domestic/I&C Services	Output based on connections and determined unit rates.
Capex over and under spend	Additional Development Area (ADA) projects submitted by FE and approved by us will retrospectively be allowed into the cost base at the time of the next review as well as approved projects to deal with Energy Efficiency. Similarly any projects within the price control which do not go ahead will be removed from the cost base.
Volumes in relation to Additional Development Areas (ADAs)	Output based on additional volumes times the determined Pi rate. Volume determination updated to reflect actual burn of ADAs.
IT	Ring-fenced allowance for 2014 as set out in section 8.

Source: The Utility Regulator

15.14 For **Opex**, the items subject to retrospective adjustment are those shown in the table below.

Table 106 – FE opex uncertainty mechanism

Opex Item	Determination Basis
Rates	Pass through.
Licence Fees	Pass through.
Connections Incentive Mechanism (inclusive of sales/support staff and related overheads)	Output based on Owner Occupier connections (excluding assessed non-additional connections) and determined unit rates (as adjusted for over/under performance with respect to target owner occupier connections. This is outlined in FE opex section 6.

Source: The Utility Regulator

Rolling Incentive Mechanism

15.15 Rolling incentive mechanisms enable licensees to retain efficiency savings for a period of years and then pass the benefits through to customers. The benefits are three-fold. Firstly a rolling mechanism can provide stronger incentives on licensees as they retain benefits in full (depreciation and rate of return) for a fixed number of years. Secondly, licensees are protected to a certain extent from unforeseen costs as the impact will only be felt for the first few years. Thirdly, customers benefit by receiving the value of the capex (after deducting the depreciation to date) for the remainder of the asset life (although customers will bear some of the cost for overspends). A five year rolling mechanism approximately equalises the benefits between licence holders and customers.

15.16 PNGL has a rolling incentive mechanism for capex applying for five years which has been effective since 2007.

15.17 The FE licence has an option to “switch on” a rolling incentive mechanism for both capex and opex.

15.18 To update for our final determination, we have decided to have a five year capex rolling incentive for FE. We have not switched on an opex rolling incentive mechanism for FE due to the number of items that are covered by the uncertainty mechanism but we will consider this in GD17.

Materiality Thresholds

15.19 GDNs can request approval from us for costs that were not foreseen at the time of the price control. Sometimes the requests for additional allowances for costs incurred can be very small, around £1,000.

15.20 It is not appropriate for us to be investigating the case for such low amounts of cost and to be revising the determination as a result.

15.21 Consequently, we are going to maintain a materiality threshold for requests for additional costs. Having carefully considered responses to our consultation, we confirm that we will set this materiality threshold at £100,000.

16 FURTHER ISSUES

Update from Draft Determination

16.1 Additional paragraphs on price control timelines and on stakeholder engagement have been introduced in this chapter, addressing some of the lessons learnt as part of this price control.

16.2 The section on energy efficiency and shrinkage of gas has been enhanced to note that we will consider business cases submitted by the GDNs for energy efficiency improvements in line with article 15(2) of the Directive on Energy Efficiency. Any such additional costs allowed will be accounted for as part of the retrospective mechanism.

16.3 An additional paragraph has been introduced in this chapter, detailing the reductions in greenhouse gas emissions resulting from the new connections to be realised by PNGL and FE during this price control period.

Introduction

16.4 Some key elements of the price control that will be considered as part of the GD17 process (primarily, the cost of capital) have been addressed in previous sections of this consultation paper. The present section briefly reviews additional matters that will impact on GD14 or that we are minded to consider as part of the GD17 price control.

Price Control Timelines

16.5 In preparation for the GD17 price control, we will consider a revision of the price control timelines. In particular, we will consider options for earlier submission of the GDN's business plans to allow more time for subsequent analysis and stakeholder engagement ahead of the final determination.

16.6 We expect that a clearly set out timetable, together with improved cost reporting will lead to better quality of submissions and enable an effective and efficient price control process.

Connection Incentive and Connections Policy

16.7 The connections incentive we have outlined for GD14 provides strong incentives for PNGL and FE to increase their connections activity and hence enables us to deliver our principal objective to promote the development of the NI gas market.

16.8 As the market matures we consider that such a strong incentive may no longer be necessary and our intention is to reduce the value of this incentive. Our current thoughts are to halve the incentive in GD17 and give further consideration to whether it should be focused on the fuel poor and areas new to gas.

16.9 In addition we expect PNGL and FE to have agreed and put in place a common approach to promoting gas connections before GD17. This could include co-ordinated branding and agreed messages so that there is a clear focus on the benefits of natural gas as a product in all areas of NI where it is available.

16.10 PNGL and FE both have connection policies to provide free connections to any customer who is within a defined proximity of a mains gas pipe. This policy has been helpful in increasing connections to gas. As the market matures we intend to reconsider this policy and may revise it for GD17. In GB, new customers pay for connections.

16.11 We will also need to determine how any energy efficiency obligation arising out of the Energy Efficiency Directive 2012/27/EU might impact on the connections incentive.

Cost Reporting

16.12 The quality of the submissions for this price control has been mixed. We began to introduce a cost reporting framework last year but while we welcome the effort FE has put into engaging on this we will need to continue its development.

16.13 In 2014 we intend to build on our cost reporting project. The intent is to evolve robust and consistent reporting templates that will enable us to have a better insight into costs and to more effectively compare costs across the two GDNs.

16.14 We include a comment on annual cost reporting from PNGL's response to our December 2012 consultation on the approach to the price controls that we fully support:

"PNGL must be able to communicate its cost forecasts to UR in a clear and effective manner which accurately reflects the operation of its business. This will facilitate transparent discussion with UR and its consultants throughout the GD14 review and ultimately facilitate its timely completion."

16.15 We expect to have a comprehensive annual cost reporting system in place that will provide us with the information that we need to undertake an effective price control in GD17. We will also consider if any licence modifications are needed to enforce the cost reporting arrangements.

Price Cap vs. Revenue Cap for FE

16.16 When PNGL commenced operations it had an annual price cap in place which provided strong incentives to outperform on volumes (as it kept the resulting revenue from outperformance). As the network matured, the strong volume incentive was no longer needed. Consequently, PNGL's control was changed to a cap on revenues in 2007.

16.17 FE currently has a price cap in place. As the business matures we are minded to change this to a revenue cap. The price control for FE will remain as a price cap in GD14 but we will be consulting on whether to change this to a revenue cap as part of GD17.

Profiling of Revenues

16.18 PNGL and FE currently defer some allowed revenue to be recovered from customers in future price controls.

16.19 This deferred revenue, the profiling adjustment, is scheduled to be unwound (i.e. reduce to zero) by 2046 for PNGL and 2035 for FE.

16.20 We believe that both FE and PNGL now have a solid base of customers. Consequently, we intend to review the profile adjustment as part of GD17 to assess whether the profile adjustment is still required or whether moving to a model more in line with GB GDNs would provide benefits.

Consumer and Stakeholder Engagement

16.21 We see the engagement of consumers and wider stakeholders (such as special interest groups, consumer bodies, current and prospective investors, banks and credit rating agencies) as an important part of the process of determining outputs and prices.

16.22 We consider that, through the consultations on the overall GD14 approach (published on 3 December 2012), the consultation on the draft price control determination (published on 16 July 2013), the stakeholder workshop held on 6 September 2013 and regular meetings with the GDNs as well as CCNI, we have provided appropriate opportunities to all stakeholders for engagement throughout the price control process. That said, we intend to set out proposals for enhanced stakeholder engagement, in particular with consumers and their representatives, for GD17.

16.23 During GD14 we have involved the Consumer Council of Northern Ireland (CCNI). CCNI has been kept informed of policy developments and has been invited to meetings with GDNs. We will continue to engage with CCNI to consider if any of its survey work could be aligned the GD17 price control.

16.24 For GD17 we will be encouraging GDNs to consult more widely with consumers and other stakeholders to better inform their business plans.

Energy Efficiency and Shrinkage Gas

16.25 Directive 2012/27/EU on Energy Efficiency was introduced on 25 October 2012[69]. This Directive amends Directives 2009/125/EC and 2010/30/EU and repeals Directives 2004/8/EC and 2006/32/EC.

16.26 This Directive establishes a common framework of measures for the promotion of energy efficiency within the European Union in order to ensure the achievement of the 20% headline target on energy efficiency by 2020 and to pave the way for further energy efficiency improvements beyond that date.

16.27 Energy efficiency is relevant for networks and one aspect of this is the treatment of shrinkage gas. We plan to review this further before 2017. While this does not have a large impact on GDN allowances given that it is mainly the responsibility of suppliers to supply shrinkage gas in NI the review will fully involve the GDNs.

[69] Directive 2012/27/EU: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:EN:PDF

16.28 The Directive sets out, in article 15 (2), the obligation to ensure that, by 30 June 2015:

(a) “an assessment is undertaken of the energy efficiency potentials of the gas and electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, and connection to energy generating installations, including access possibilities for micro energy generators; and

(b) concrete measures and investments are identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction.”

16.29 Any involvement required by the GDNs in providing the assessment of energy efficiency potentials, identifying concrete measures and investments and providing a timetable for their introduction is considered to be part of the normal business operations; therefore, no relating allowances have been made in this price control.

16.30 The timetable for introduction of the energy efficiency improvements identified may suggest implementation of certain measures during the current price control period. This may entail additional costs which cannot be reasonably quantified at the time of this price control. Therefore, no relating allowances have been made at this stage. However, we will consider business cases submitted by the GDNs for energy efficiency improvements to be introduced in line with article 15(2) of the Directive before the end of the price control period. Any additional costs allowed based on such business cases will be accounted for as part of the retrospective mechanism.

Environmental Impact of New Connections

16.31 As part of their operations, the GDNs will connect new customers to the natural gas network. This will entail an increase in the burn of natural gas as well as a reduction in the burn of fuels these customers have been using up to their conversion to natural gas, i.e. in particular of oil and coal. The environmental impact of these changes can be measured as the related reduction of greenhouse gas emissions. In line with Government Guidance on the valuation of energy use and greenhouse gas emissions[70,] the standard unit of account for greenhouse gas emissions is equivalent tonnes of carbon dioxide (tCO_2e), i.e. the equivalent amount of CO_2 that would have the same global warming potential as a given greenhouse gas emission.

16.32 Table 107 provides an overview over the additional volumes of natural gas that will be burnt between 2014 and 2016 by properties newly connected during the course of this price control period. These figures are based on the following assumptions:

- Of the domestic customers switching to natural gas, 97.9% are switching from oil and 2.1% are switching from coal.
- Of the I&C customers switching to natural gas, 90% are switching from oil and 10% are switching from coal.
- Volumes for PNG domestic, small and medium I&C and large I&C customers are based on volume differences from one year to the next, assuming that all such differences are due to new connections.
- Volumes for FE domestic new connections are based on an average burn of 394[71] therms p.a., volumes for FE small and medium I&C customers on an

[70] For further details, see Department of Energy and Climate Change: Valuation of energy use and greenhouse gas (GHG) emissions, October 2012.

[71] This equates to the assessment of FE volumes for the P1 category in GD14. See chapter 9 for further detail.

average burn of 5,051 therms p.a. and volumes for FE large I&C customers are based on average FE figures.

- All volumes for owner occupier new connections are based on the assumptions detailed in chapters 5 and 6.
- All new connections happen on average mid-year and continue to burn during subsequent years.
- Efficiency effects from installing new boilers in newly connected properties can be neglected. Were such effects to be taken into consideration, the reduction in greenhouse gas emissions could be expected to be even more significant, as it would then need to be assumed that the energy consumption of these customers of oil and coal would be even bigger than their equivalent natural gas one.

Table 107 – New Connection Volume Overview 2014-2016

Volume (GWh)	PNGL				FE			
	2014	2015	2016	Total	2014	2015	2016	Total
Domestic	96	189	279	564	23	69	114	207
of which Owner Occupier	*78*	*78*	*78*	234	*12*	*35*	*58*	104
Small and Medium I&C	17	35	52	105	11	30	41	81
Large I&C	3	5	9	17	1	4	6	11
Total	116	229	341	686	35	103	161	299

Source: PNGL, FE and the Utility Regulator

16.33 Based on the volumes detailed in Table 107 and with consideration of the Government guidelines for the calculation of greenhouse gas emissions[72], the reduction in CO_2 resulting from the new connections can be determined. Table 108 shows the results for PNGL and FE, both for all new connections expected to be achieved during the price control period and for new owner occupier connections expected to be made under the new incentive scheme (see chapters 5 and 6 for further details). Table 109 shows the same information, but with respect to the reduction in CO_2.

Table 108 – Reduction in ktCo$_2$e from new connections

Reduction in tCO$_2$e resulting from ...	PNGL				FE			
	2014	2015	2016	Total	2014	2015	2016	Total
All new connections	8,085	15,912	23,818	47,814	2,681	7,678	11,870	22,230
New owner occupier connections	4,965	4,965	4,965	14,895	734	2,202	3,670	6,606

Source: PNGL, FE and the Utility Regulator

Table 109 – Reduction in ktCo$_2$ from new connections

Reduction in tCO$_2$ resulting from ...	PNGL				FE			
	2014	2015	2016	Total	2014	2015	2016	Total
All new connections	7,413	14,580	21,784	43,777	2,329	6,716	10,491	19,536
New owner occupier connections	4,830	4,830	4,830	14,491	714	2,142	3,571	6,427

Source: PNGL, FE and the Utility Regulator

[72] See https://www.gov.uk/government/policies/using-evidence-and-analysis-to-inform-energy-and-climate-change-policies/supporting-pages/policy-appraisal for further details.

Meter Reading

16.34 Gas suppliers are responsible for meter reading in both gas networks in NI. This responsibility currently falls on gas suppliers through licence obligations.

16.35 We will consider further in GD17 if this is still appropriate or whether responsibility for meter readings should be moved to GDNs.

Change in Ownership Structure

16.36 It is possible that FE and PNGL could end up under common ownership. Under the terms of their licences, any change of ownership must be approved by us.

16.37 Our expectation, in particular if FE and PNGL come under common ownership, is that there may be synergies and other cost savings that can be achieved.

16.38 As a consequence, it may be appropriate to re-open this price control for any change of ownership depending on the exact timing. If the businesses come under common ownership we would seek to ensure that the resulting synergy cost savings are shared between the GDNs and consumers.

GDN's Working Together

16.39 As both FE and PNGL work in a similarly industry and geographical region, we believe there is merit in ensuring a similar approach to how they operate.

16.40 Although both FE and PNGL have separate license, we believe that certain synergies can be made if a standard approach is adopted, which could be used throughout Northern Ireland.

16.41 We encourage both companies, where practically possible to work together to develop an efficient and growing gas industry.

16.42 We recognise that his occurs at some levels, but we believe further work is necessary to achieve a more co-ordinated approach.

16.43 We would especially encourage further work in the following areas:

- Advertising and Marketing/ Consumer Research;
- Conveyance Charges;
- Connection Policies;
- Emergencies and Major Incidents.

17 NEXT STEPS

Implementation of the Price Control

17.1 There is no licence modification required to implement this price control.

17.2 Assuming that PNGL and FE do not disapply our final determination, the price control for 2014 will be implemented.

17.3 In the event that either PNGL or FE disapply our final determination we can refer the matter to the Competition Commission in line with conditions set out in the PNGL and FE conveyance licences.

Appendix 1
Emergency Call Centre Costs

Overview

1.1 This Appendix provides additional information on how the allowances have been determined for both PNGL's and FE's Emergency Call Centre Costs. This appendix should be read in conjunction with the PNGL Emergency & Maintenance section within section 5 and FE Emergency & Maintenance section within section 6.

1.2 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

Call Centre Modelling

1.3 A model was developed in order to determine allowances for call centre costs for GD14 based on appropriate call numbers and call centre costs. This section provides details on the model including the principals and assumptions of the model and the outputs from the model.

1.4 The principal driver for the call centre activity is the total number of customers connected to the network. Rune believes that the trend for number of calls per 10,000 customers should indicate a reduction. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that initially may generate a higher emergency call rate.

1.5 The model incorporates a higher number of calls from new customers compared to existing customer calls which should be reducing. Also, the trend forward does not reflect high levels of calls resulting from the cold winter conditions in 2010 and 2011 as the forecast should be based on mid-point estimates and not exceptional peaks in activity.

1.6 The model developed is based on the following principles and assumptions:

- Actual call volumes for 2010, 2011 and 2012 provide the basis for the model.
- The total number of calls is made up of three components; gas emergencies (including escapes), meter problems (particularly electronic prepaid meters) and incorrect calls.
- FE have reported a material number of warranty calls (call outs whereby their contractor takes corrective action at their own cost) these calls, which are falling as a percentage of the total number of calls, have been excluded from the modelling carried out as to include them would embed these volumes into the model.
- Based on Rune experience and the level of installation problems, calls from new customers in year are higher than existing customers. The model assumes 1,951 calls per 10,000 existing customers and 3,813 per 10,000 new customers.
- Based on the total historical actual calls (2010, 2011 & 2012) for PNGL & FE 50% of calls are general enquiry calls.

- 3% per year target reduction in calls from existing customers from 2015, resulting in 1,835 calls per 10,000 customers in 2016.
- 1% per year target reduction in calls from new customers from 2015, resulting in 3,737 calls per 10,000 customers in 2016.
- Forecast call numbers are derived from the forecast number of customers.
- Cost estimates for calls handled are based on the reported costs for the years 2010 & 2011 and standard figures are used for both companies - £99k per year fixed costs, £19.03 per emergency call, £4.76 per incorrect call in 2014. In 2015 a 12% improvement target has been set which reduces these figures in 2015 & 2016 to £87k per year fixed costs, £16.75 per emergency call and £4.19 per incorrect call.

1.7 GD14 forecast activity generated by the model is at a higher level compared to the levels typically seen by gas distribution networks in GB, even allowing for a large number of prepaid meter problems which are not directly comparable between NI installed volumes and GB. We therefore consider the target reductions in numbers are set at an achievable level

Call Centre Contract

1.8 As outlined in the paper, both PNGL & FE have a contract with National Grid to handle all of NI's gas emergency calls. In the consultation paper we determined that lower costs for this service should be obtained by working more closely together in the provision of an emergency call centre for the whole of NI. Both PNGL & FE have provided comments to the effect that they already liaise on the contract and that no further savings are possible from this approach.

1.9 Both Rune and ourselves have reviewed the information provided in the response to the consultation and have met with both PNGL & FE to discuss this information. Although we acknowledge that they both use the same contract, essentially FE "piggyback" upon the contract negotiated by PNGL. It is clear that FE has limited input to the contract negotiations and we remain unconvinced that all of the economies of scale from a combined approach have been realised.

1.10 It is clear that the National Grid contract provides a robust and professional service, itself exploiting the resources used to deliver the gas emergency service for the whole of GB. In addition the scale of the National Grid operation provides opportunities for a rapid increase the in the number of calls received during times of incident conditions, such ability is not a contractual commitment and is provided on a "best endeavours basis". Even so, this ability is an important consideration.

1.11 The combined submission from PNGL & FE for this service in 2016 is £811,000. We believe that for the volume of calls being typically handled, this represents a significant premium on the costs of running a standalone service in NI. It is clear that neither PNGL nor FE have considered developing a detailed costing for establishing such an operation in NI. We have asked Rune to provide high level estimates of the scale of costs which would be involved. They have estimated costs ranging from £385k to £450k. Included within these costs are potential minutes of "spare" clerical time which could be exploited during period of low call volume to the benefit of the distribution businesses.

1.12 We have no wish to suggest that the arrangement for emergency call handling should be changed from the current provider or that an independent NI call centre should be established. However we do believe the companies should seriously consider other options.

1.13 In consideration of the responses received we have decided to defer our efficiency challenge in this area for one year to start in 2015. In addition we have concluded that it would be more appropriate implement the efficiency challenge in proportion to the expenditure in each company. Accordingly we have reduced the modelled costs based on the company's performance in 2010 & 2011 by 12% in years 2015 & 2016.

APPENDIX 2
PNGL Emergency & Network Maintenance Costs

Overview

1.1 This Appendix provides additional information on how the allowances have been determined for PNGL's Emergency and Network Maintenance Costs. This appendix should be read in conjunction with the PNGL Emergency & Maintenance section within section 5.

1.2 As outlined in the paper, both PNGL & FE have to date reported costs and forecasts for emergencies and maintenance in terms of the account headings used within their businesses. However, to undertake the review for the GD14 price control for both PNGL and FE, we asked Rune to develop a reporting template that would attempt to get both companies to move to a common reporting format and would provide an element of comparability to GB networks.

1.3 The emergency and maintenance costs will be reported under the following headings:

- Call centre costs
- Emergencies (First Call Costs)
- Repair activities
- Maintenance activities

1.4 In this Appendix we provide additional detail on the models developed for call centre costs, emergencies and maintenance activities.

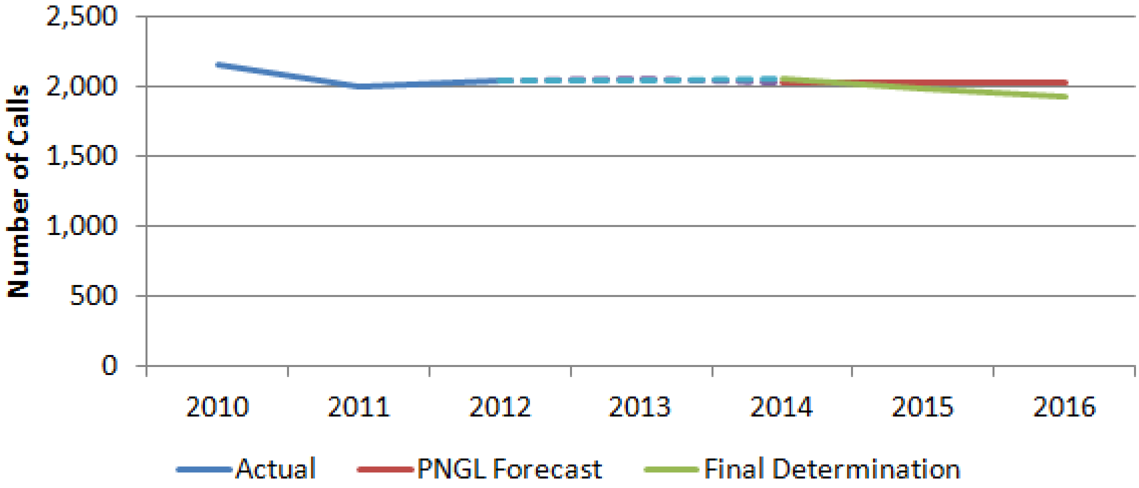
1.5 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

Call Centre Costs

1.6 As outlined in Appendix 1, a model was developed in order to determine allowances for call centre costs for GD14 based on appropriate call numbers and call centre costs. This section provides details of the impact of this modelling on our determinations.

1.7 Figure 1 below displays the number of calls per 10,000 customers as requested by PNGL against the number determined through the analysis model.

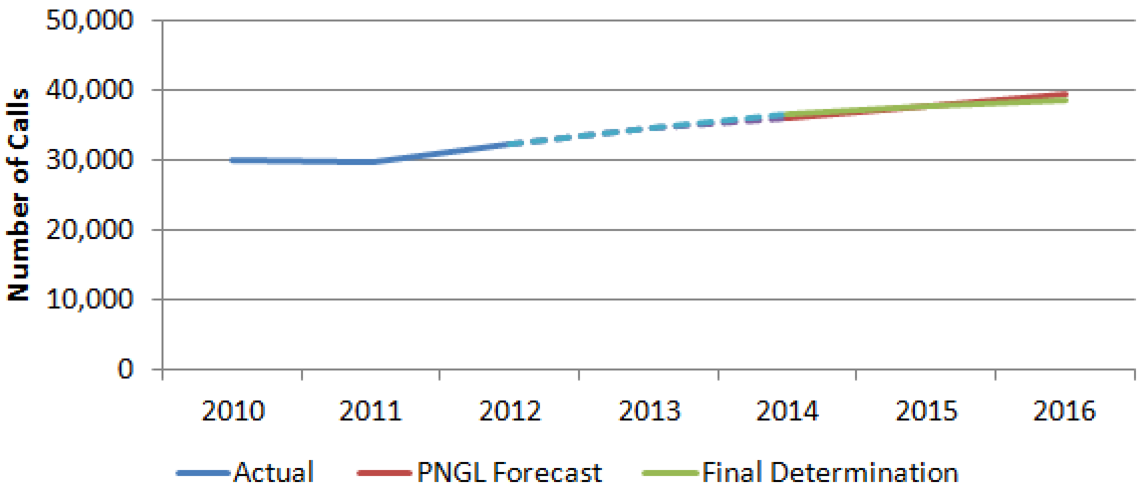
Figure 1 – PNGL Emergency Call Rate Information per 10,000 Consumers



Source: PNGL and the Utility Regulator

1.8 As shown in the graph below, the model assumes an increasing call volume trend, for the total number of calls, albeit at a slightly lower level than the PNGL forecast submission. The model incorporates efficiency improvements of between 1% and 3% as outlined in the principals and assumptions set out in Appendix 1. The comparison with PNGL's forecast is shown in Figure 2 below. The effect of the reduction within the model for the number of calls per 10,000 customers is partly offset by our assumptions for higher numbers of connections in the period 2014-16.

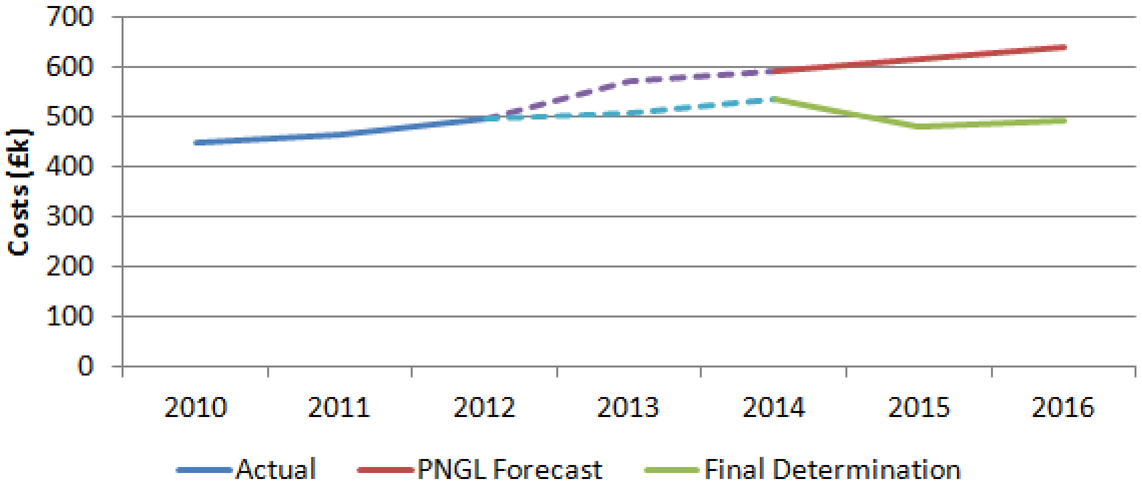
Figure 2 – PNGL Total Emergency Calls



Source: PNGL and the Utility Regulator

1.9 The combination of call volumes and the cost per call generated by the model results in an increasing trend in total call centre costs. However, when the 12% performance challenge for the call centre contracts is applied, the result is a step-change reduction in our determined costs for 2015. This is shown in Figure 3 below along with a comparison of PNGL's requested allowances.

Figure 3 – PNGL Emergency Call Centre Costs, £k



Source: PNGL and the Utility Regulator

1.10 The determined allowances for call handling are detailed in the table below:

Table 1 – Emergency call centre workloads and costs for PNGL

Cost element	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergency Calls (no.)	29,914	36,020	37,698	39,420	36,694	37,691	38,628
Cost per Emergency Call (£)	*15*	*17*	*16*	*16*	*15*	*13*	*13*
Total Emergency Call Centre Cost (£k)	460	596	620	644	540	486	496

Source: PNGL and the Utility Regulator

Emergencies (First Call Costs)

1.11 A model was developed to determine allowances for first call costs. This section provides details on the model including the principles and assumptions of the model and the outputs from the model.

1.12 The principal driver for emergency activity is the total number of customers connected to the network.

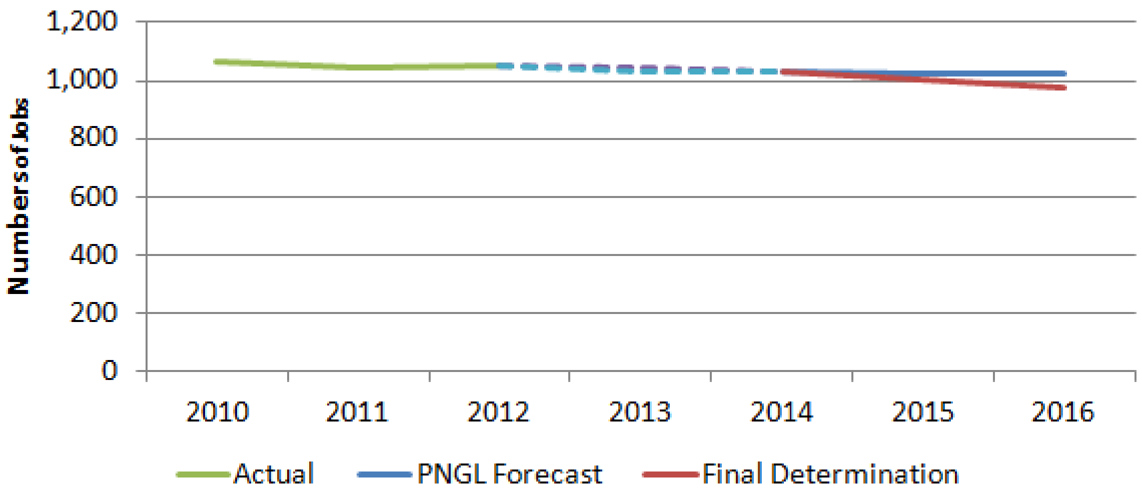
1.13 The model generates a declining trend in activity, as shown in Figure 4 below. Also, the trend forward does not reflect high levels of calls resulting from the cold winter conditions in 2010 and 2011 as the forecast should be based on mid-point estimates and not exceptional peaks in activity.

1.14 The model is based on the following principles and assumptions:

- Workload projections are based on the 2010-2012 calls to jobs ratio for both PNGL and FE and the call model described in Appendix 1.
- Forecast Costs for 2014-2016 are modelled, based on £350k fixed cost and a variable cost of £69.52 per emergency job, and rolled forward.

1.15 PNGL forecast a slight falling trend in the number of emergency jobs per 10,000 customers whereas the model generates a larger reduction, as shown in Figure 4 below. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that are initially likely to generate a higher emergency workload.

Figure 4 – PNGL First Call Emergency Workload Rate Information per 10,000 Consumers

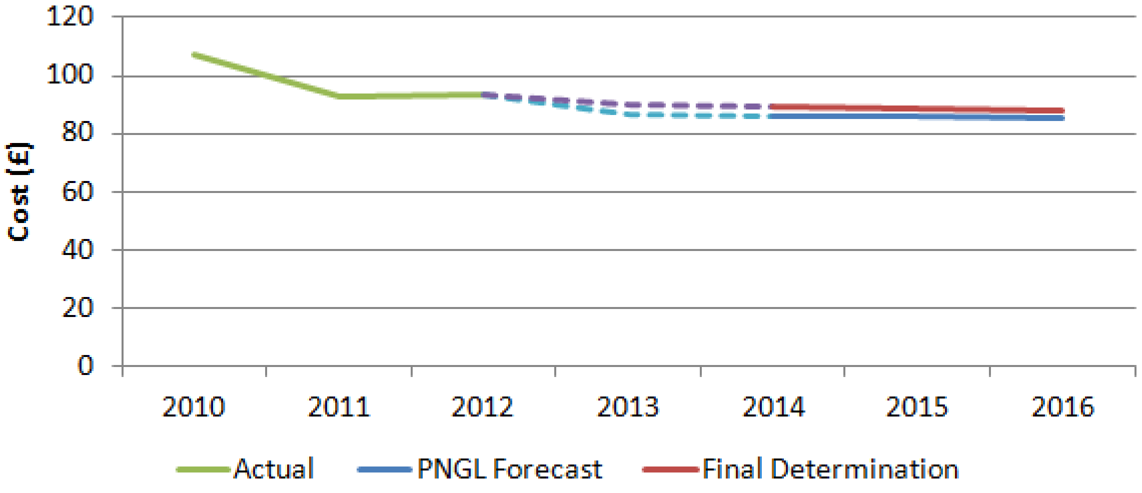


Source: PNGL and the Utility Regulator

1.16 PNGLs' actual costs per emergency show a reducing trend over the period 2010 – 2011 and a forecast flat ongoing trend. Figure 5 below indicates the comparison between the PNGL forecast cost per emergency and the model output cost per emergency.

1.17 The modelled costs per emergency show a very slight increase in the unit rate compared with the PNGL submission due to a reduction in the estimated number of emergency calls being forecast in our model which each take a higher share of the assumed fixed costs for delivering the emergency service.

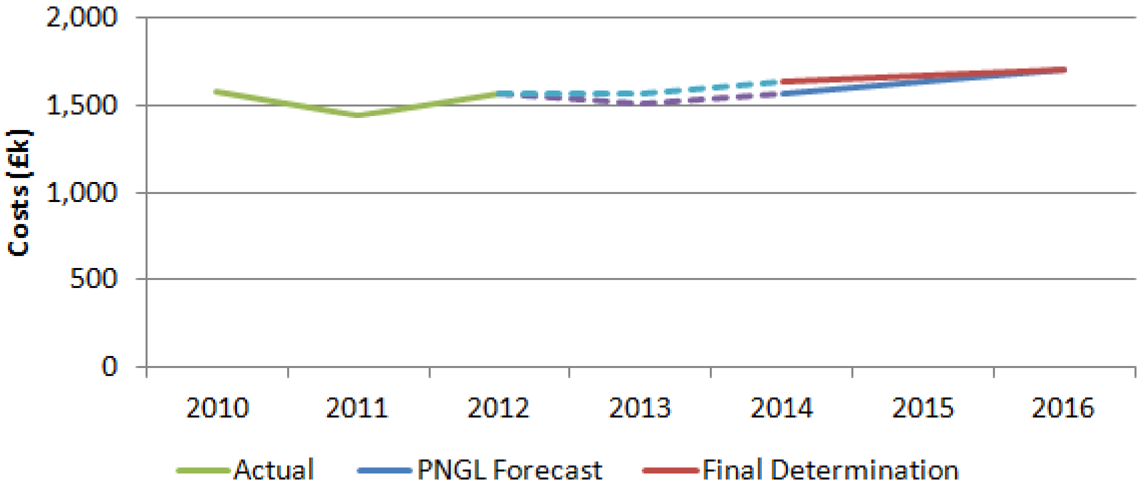
Figure 5 – PNGL First Call Emergency Workload Unit Costs



Source: PNGL and the Utility Regulator

1.18 PNGL's total first call emergency actual costs show a reducing trend over the period 2010 – 2011 and a substantial rising trend in the forecast period. Figure 6 below indicates the comparison between the forecast cost and the model output total cost for first call emergency activity. Our modelling broadly results in a similar level of overall cost with small differences in the phasing before related company (PES) profit adjustments.

Figure 6 – PNGL Total First Call Emergency Costs



Source: PNGL and the Utility Regulator

1.19 The determined allowances for first call emergency costs are detailed in the following table.

Table 2 – PNGL First Call Emergency Allowances

Cost element	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergencies (no.)	15,156	18,200	19,048	19,918	18,449	18,951	19,421
Cost per Emergency Job (£)	*100*	*86*	*86*	*86*	*89*	*89*	*88*
Assessed Emergency Cost (£k)	1,512	1,566	1,634	1,703	1,643	1,678	1,711
PES Profit Element (£k) (14%)					230	235	240
Total Emergency Cost (£k)	**1,512**	**1,566**	**1,634**	**1,703**	**1,413**	**1,443**	**1,471**

Source: PNGL and the Utility Regulator

Maintenance Activities

1.20 As outlined in the PNGL Emergency & Maintenance section of this paper, we have taken the approach of reviewing the detailed actual expenditures reported by both companies and setting to one side items considered exceptional (i.e. not a regular and consistent item of expenditure). This expenditure has then been rolled forward from the levels at 2011 through 2012 & 2013 to provide a base level of expenditure in 2014-2016.

1.21 We then looked at adding to this base level of expenditure items which have been identified by the PNGL as being a justified extra expenditure required in the years 2014-2016. We were not convinced that certain items have been sufficiently justified as expenditure required in the GD14 period; therefore some items have been excluded from the recommended allowances.

1.22 This section will provide additional information on the model, including the principals and assumptions upon which it is based. This section also provides detail on the costs which have been excluded to create the baseline costs and the analysis of the costs which are to be added back for 2014-2016

Analysis model

1.23 The historical maintenance reported costs have been reviewed and items considered to be exceptional have been separated out in order to create the baseline maintenance costs.

1.24 The model then uses customer numbers as a primary driver to roll forward the base level expenditure into the forecast years.

1.25 The model is based on the following principles and assumptions:

- Actual Maintenance costs for 2011 provide the basis for the model (assessed in conjunction with the costs reported in 2010 & 2011).
- Using detailed information provided by PNGL the model has been developed to allocate a cost of maintenance for each I&C customer. A further cost for every customer (I&C & Domestic) has been included within the model set at a rate of 47% of the rate set for I&C customers. These rates are set such that the model produces the same actuals for 2010 & 2011 that have been reported by PNGL (excluding exceptional costs).

Actual Costs Excluded for Baseline

1.26 The actual costs incurred in 2010 & 2011 were reviewed and an assessment made of which costs were considered exceptional items and would not be rolled forward into the baseline maintenance. These costs are listed in the table below.

Table 3 – Establishing the Base Maintenance Costs for PNGL

Cost element	PNGL Actuals	
	2010	2011
Actual Maintenance Costs	**1,736,549**	**2,021,991**
Exceptional Items	**860,145**	**945,524**
DSEAR	125,394	160,236
SWR Domestic	398,047	427,225
SWR I&C	19,448	9,364
Battery Changes	252,111	306,872
Energy Care Equipment	14,344	16,596
>U6 meter stock provision	50,801	25,232
Established Base Cost	**876,404**	**1,076,466**

Source: PNGL and the Utility Regulator

Assessment of Exceptional Items in Forecast

1.27 Following the establishment of the base maintenance costs using the model described above we have then considered which forecast exceptional items had been justified to be added on top of the base costs. We were not convinced that certain items have been sufficiently justified and have therefore been excluded from the determined allowance.

1.28 The adjustments to the added back costs have been developed on the following basis:

- Replacement Telemetry

  We note that PNGL propose to replace telemetry equipment at key sites during the GD14 period. PNGL's requested costs have been allowed based on the information provided by PNGL. However we note that PNGL has not provided a detailed cost benefit analysis in relation to the telemetry project. We therefore expect PNGL to produce a detailed report at the end of 2015 describing the work carried out, and detailing the benefits and costs incurred. We will consider this at the next price control.

  We also note that FE is also seeking to upgrade its telemetry systems in the GD14 period and we therefore expect PNGL and FE to work together to find the most efficient and beneficial solution.

- SWR Domestic

  PNGL have substantially increased the forecast number of SWR jobs from their forecasts in

PNGL12. They have provided no explanation for this, and we consider that the new forecasts are unreasonably high. We are also aware that PNGL do in fact charge domestic customers directly for some SWR jobs that are carried out, and in accordance with their connection policy many other SWR jobs will be charged to the relevant Supplier who can pass on the charge to the customer. We have therefore determined new SWR Domestic job numbers based on the ratio of jobs to customers forecast in PNGL12 and rolled forward.

PNGL state that meter exchanges make up 65% of the total Domestic SWR jobs and we accept this. We have then calculated the number of meter exchanges for credit to prepay and vice-versa based on the PNGL12 forecast breakdowns.

In accordance with the proposed change of policy outlined in the Maintenance section of section 5, we are granting allowances for meter exchanges from credit to prepay and additional SWR jobs including meter box repairs, quality inspections etc. Full allowances for meter exchanges from prepay to credit will not be allowed, with the exception of an allowance for January to March 2014 to allow a three month window for PNGL and suppliers to implement the change of policy.

- PAYG Switches — The allowance has been set to zero for this category as PNGL state that they are not in a position to distinguish the reason for a meter exchange and therefore any meter exchanges requested due to the customer changing supplier will be included in the SWRs.

- SWR I&C — The allowance has been set to zero for this category as we consider that a customer should be charged for the costs of a meter exchange where requested

- Battery Changes — Following additional justification provided by PNGL in relation to battery changes, we now accept that a ten year life is appropriate and therefore we have updated the determined allowance to grant the full costs requested by PNGL.

- RCM Upgrades — We have reconsidered this area of cost for the final determination and have concluded that these costs should not be allowed under the GD14 price control. PNGL identified these issues during the previous price control period. Therefore we are of the opinion that PNGL should have completed the

	work required under RCM Upgrades when it was identified, especially given that PNGL's actual maintenance costs in 2012 were significantly lower than the allowance determined in the PNGL12 price control.
• Energy Care Equipment	PNGL have not given sufficient explanation as to why costs are not responsibility of the Supplier therefore we have not granted any allowance for this area of cost.
• >U6 Meter Stock Provision	PNGL have not given sufficient information as to why the provision grows year on year and we are not aware of any reason why PNGL would need to increase their existing meter stock year on year therefore no allowance has been granted.

1.29 The resulting costs for the assessment of exceptional items are given in the following table

Table 4 – PNGL Maintenance Added Back Costs

Item (Costs £)	PNGL Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
PNGL Submitted Base Costs	**1,241,699**	**1,463,409**	**1,228,860**			
Modelled Base Costs				**1,203,610**	**1,271,541**	**1,340,723**
Exceptional Items Added Back	**1,159,626**	**1,167,839**	**1,107,072**	**737,237**	**744,036**	**739,859**
PAYG switchers	86,086	113,003	118,268	0	0	0
Replacement Telemetry	33,915	33,915	0	33,915	33,915	0
SWR Domestic	436,703	451,785	456,077	289,007	283,524	295,941
SWR I&C	25,885	26,598	27,312	0	0	0
Battery Changes	414,315	426,597	443,918	414,315	426,597	443,918
RCM Upgrades	103,345	55,493	0	0	0	0
Energy Care Equipment	20,486	21,557	22,605	0	0	0
>U6 meter stock provision	38,892	38,892	38,892	0	0	0
Total Maintenance	**2,401,325**	**2,631,248**	**2,335,931**	**1,940,847**	**2,015,577**	**2,080,582**

Source: PNGL and the Utility Regulator

1.30 We have also disallowed the profit margin on all PES activity and we have therefore removed the 14% profit element from the maintenance activities which are carried out by first call operatives. This is also explained in section 5 of the paper, and the effect is shown in the following table. This table shows the determined allowances for maintenance.

Table 5 – PNGL Maintenance Allowances

Cost element (£k)	Average 2010-2011	PNGL Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Total Assessed Maintenance Cost	1,879	2,401	2,631	2,336	1,941	2,016	2,081
Assessed Maintenance Cost (PES Related)	1,323	1,686	1,778	1,724	1,428	1,388	1,514
Assessed Maintenance Cost (other)	556	716	853	612	513	627	567
PES Profit Element (14%)					-200	-194	-212
Allowance	**1,879**	**2,401**	**2,631**	**2,336**	**1,741**	**1,821**	**1,869**

Source: PNGL and the Utility Regulator

APPENDIX 3
FE Emergency & Network Maintenance Costs

Overview

1.1 This Appendix provides additional information on how the allowances have been determined for FE's Emergency and Network Maintenance Costs. This appendix should be read in conjunction with the FE Emergency & Maintenance section within Chapter 6.

1.2 As outlined in the paper, both FE & PNGL have to date reported costs and forecasts for emergencies and maintenance in terms of the account headings used within their businesses. However, to undertake the review for the GD14 price control for both companies, we asked Rune to develop a reporting template that would attempt to get both companies to move to a common reporting format and would provide an element of comparability to GB networks.

1.3 The emergency and maintenance costs will be reported under the following headings:

- Call centre costs
- Emergencies (First Call Costs)
- Repair activities
- Maintenance activities

1.4 As stated in the draft determination, we had some difficulty in interpreting how FE's costs are allocated under the four headings within emergency and maintenance costs and therefore some assumptions were made in order to arrive at the proposals presented in the draft determination. We have continued to work with FE to resolve the allocation issues and have now agreed the allocations between the four headings with FE. As a result the allocation of costs between the four headings has now changed for the final determination.

1.5 Following discussions and clarifications with FE, we have also reallocated some costs from the parental recharges cost line into the emergency and maintenance cost line for the final determination.

1.6 In this Appendix we provide additional detail on the models developed for call centre costs, emergencies and maintenance activities.

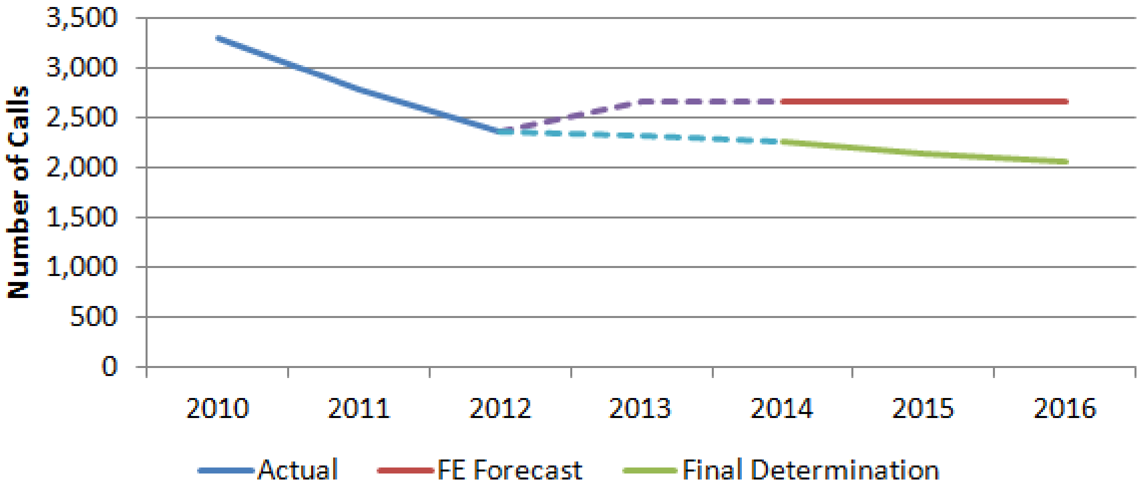
1.7 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise.

Call Centre Costs

1.8 As outlined in Appendix 1, a model was developed in order to determine the allowances for call centre costs for the GD14 based on appropriate call numbers and call centre costs. This section provides details of the impact of this modelling on our determinations.

1.9 Figure 1 below displays the number of calls per 10,000 customers as requested by FE against the number determined through the analysis model.

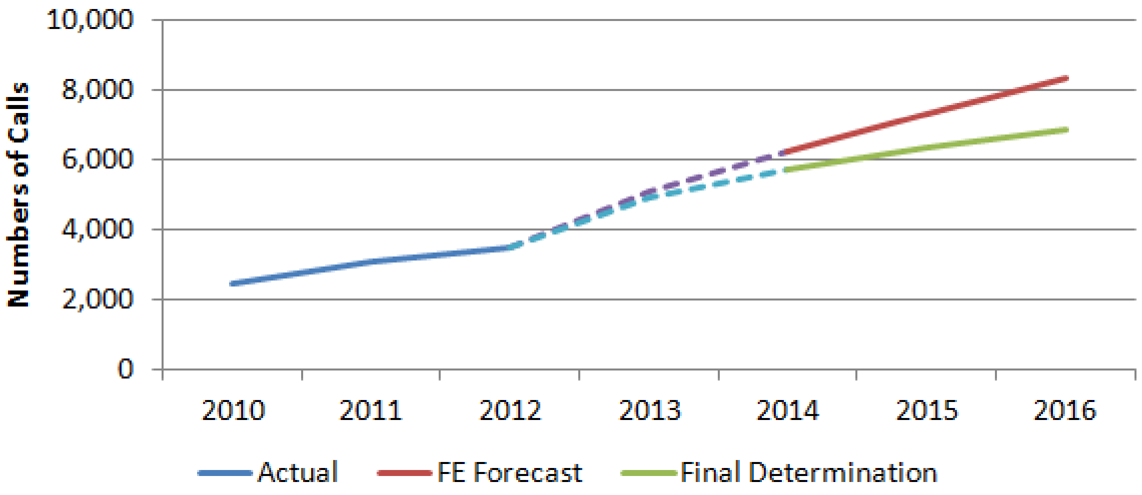
Figure 1 – FE Emergency Call Rate Information per 10,000 Consumers



Source: FE and the Utility Regulator

1.10 The model assumed a trend for the total number of calls which incorporates the efficiency improvement between 1% and 3% which are outlined in Appendix1. Figure 2 displays a comparison of FE's forecast for the total number of calls and the modelled number of calls. The model is forecasting a lower level to that requested by FE in the years 2014, 2015 & 2016. However, it is important to note that FE forecast a step up in 2013 compared to the trend of actuals up to 2012.

Figure 2 – FE Total Emergency Calls

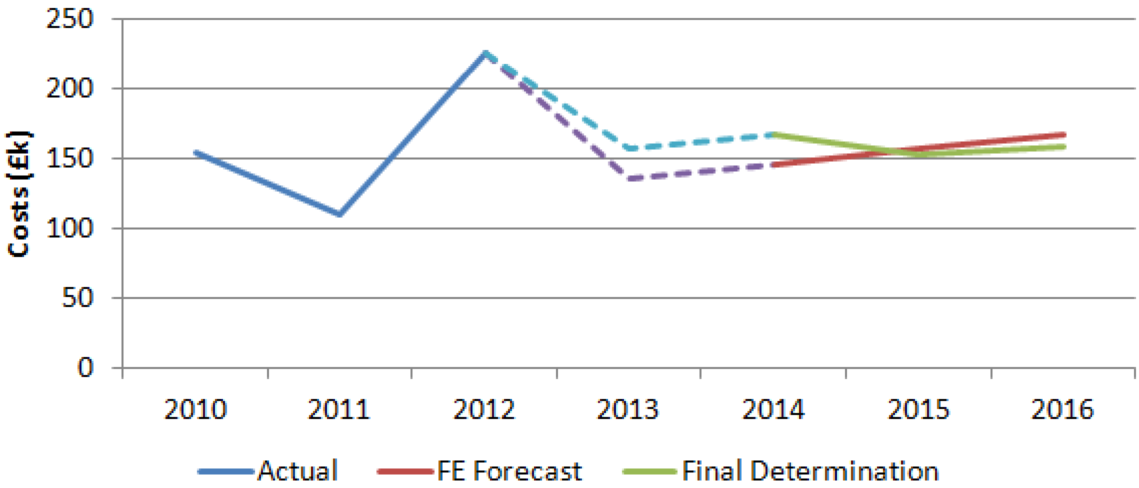


Source: FE and the Utility Regulator

1.11 The call volumes and the cost per call generated by the model are used to set the total determined costs. The model initially recommends higher costs in 2014 than proposed by FE. This is due to the fact that in 2012 FE connected a larger number of customers than the forecast and the model starts with this higher number of customers.

1.12 The step change in our recommendation in 2015 relates to the 12% performance challenge for the call centre contracts. This is shown in Figure 3 below along with a comparison on FE's requested allowances.

Figure 3 – FE Emergency Call Centre Costs



Source: FE and the Utility Regulator

1.13 The determined allowances for call handling are detailed in the table below.

Table 1 – FE Emergency Call centre Allowances

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergency Calls (no.)	2,772	6,213	7,310	8,339	5,733	6,359	6,859
Cost per Emergency Call (£)	*48*	*24*	*21*	*20*	*29*	*24*	*23*
Total Emergency Call Centre Cost (£k)	133	146	157	167	167	154	159

Source: FE and the Utility Regulator

Emergencies (First Call Costs)

1.14 A model was developed to determine allowances for first call costs. This section provides details on the model including the principles and assumptions of the model and the outputs from the model.

1.15 The principal driver for emergency activity is the total number of customers connected to the network. FE forecast an on-going increase in the number of emergency jobs per 10,000 customers, whereas Rune believes that the trend should indicate a moderate reduction. This view is based on the increasing scale of the established customer base relative to the level of new customer connections that initially is likely to generate a higher emergency workload. Also, the trend forward does not reflect high levels of calls resulting from the cold winter conditions in 2010 and 2011 as the forecast should be based on mid-point estimates and not exceptional peaks in activity. This trend is shown in Figure 4 below.

1.16 Following the responses to the draft determination, we have reviewed the actual costs being incurred by FE for the emergency activities. This review has established that a large amount of cost was being incorrectly reported under maintenance activities. Having amended this for the final determination, this has increased the assessed actual costs for the emergency process and consequently the recommendations have been increased accordingly.

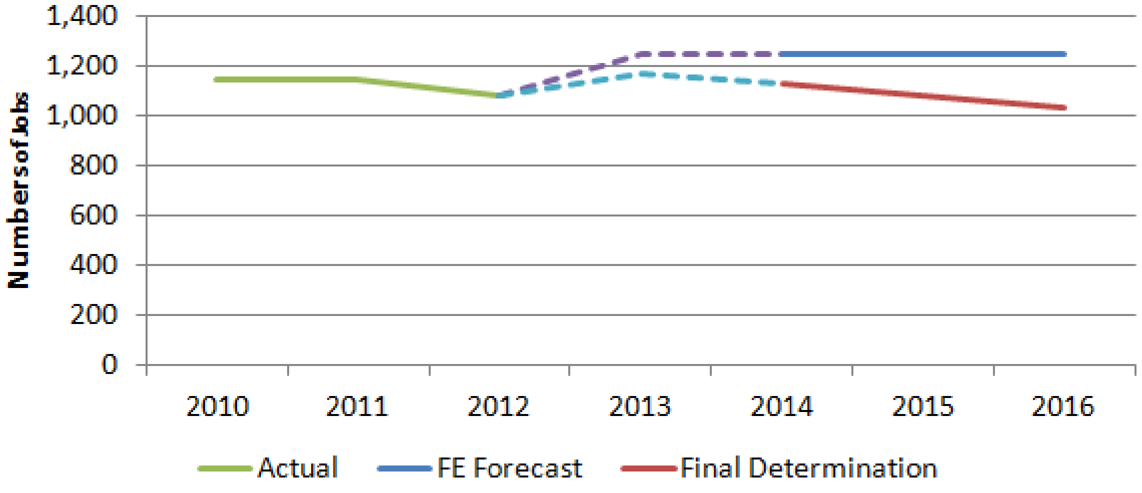
1.17 The actual workloads have been influenced by a number of warranty jobs (call outs whereby their contractor takes corrective action at their own cost). These jobs have been discounted in the assessment of forecast job numbers in the model.

1.18 The model is based on the following principles and assumptions:

- Workload projections are based on the 2010-2012 calls to jobs ratio for both PNGL & FE and the emergency call model described in Appendix 1.
- Forecast Costs for 2014-2016 are modelled, based on £195k fixed cost and a variable cost of £143.43/ emergency job, and rolled forward.

1.19 FE forecasts a step change in the number of emergency jobs per 10,000 customers in comparison to the actual levels reported. There is no evidence for any increase in the number of calls per 10,000 customers and taking account of the expected fall towards GB levels as the gas market matures the model generates a reduction in jobs per 10,000 customers, as shown in Figure 4 below.

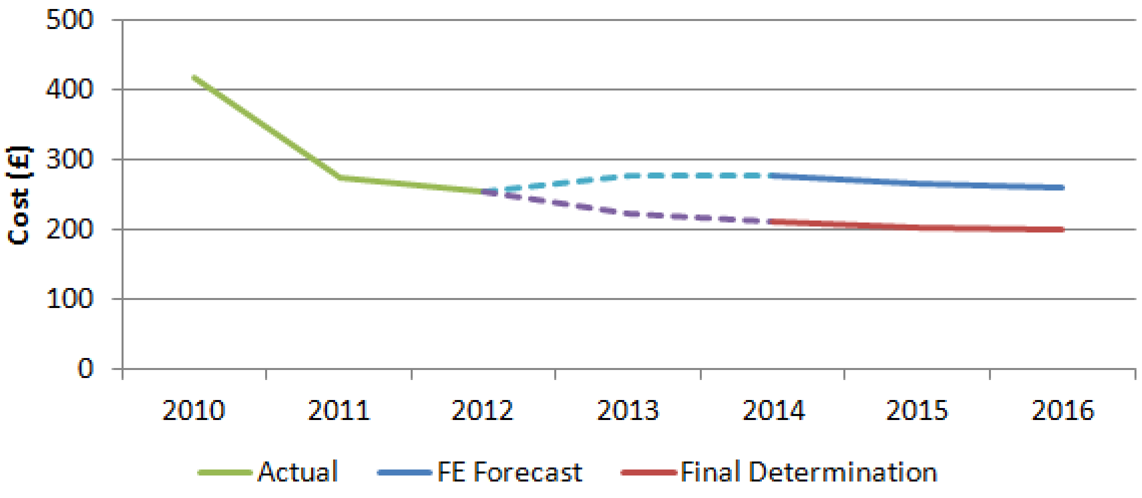
Figure 4 – FE First Call Emergency Workload Rate Information per 10,000 Consumers



Source: FE and the Utility Regulator

1.20 FEs' actual costs per emergency job show a substantial reducing trend over the period 2009 – 2012; however they have forecast a slight increase in 2013 and 2014. The model continues the downward trend from the actual costs incurred. Figure 5 below indicates the comparison between the FE forecast costs and the model output cost per emergency job.

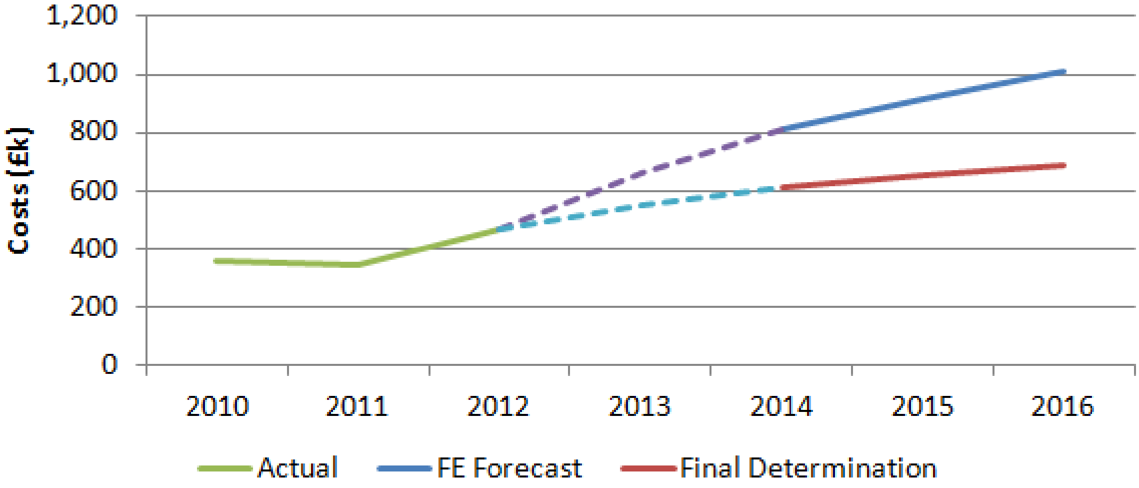
Figure 5 – FE First Call Emergency Workload Unit Costs



Source: FE and the Utility Regulator

1.21 FE's total first call emergency costs show an increasing trend over the period 2012 – 2016. The combination of workload and the unit cost results in the model also generate an increasing trend but at a lower level than FE's forecast. Figure 6 below indicates the comparison between the forecast costs and the model output total cost for first call emergency activity.

Figure 6 – FE Total First Call Emergency Costs



Source: FE and the Utility Regulator

1.22 The determined allowances for first call emergency costs are detailed in the following table.

Table 2 – FE Emergency Workload Allowances

Cost element	Average 2010-2011	FE Submission			Final Determination		
		2014	2015	2016	2014	2015	2016
Emergencies (no.)	1,062	2,905	3,418	3,899	2,883	3,197	3,449
Cost per Emergency Job (£)	*332*	*279*	*267*	*259*	*211*	*204*	*200*
Total Emergency Cost (£k)	352	810	914	1,010	608	654	690

Source: FE and the Utility Regulator

Maintenance Activities

1.23 The FE Emergency & Maintenance section of section 6 outlines the approach that we have taken of reviewing the detailed actual expenditures reported by both companies and setting to one side items considered exceptional (i.e. not a regular and consistent item of expenditure). This expenditure has then been rolled forward from the levels at 2010-2011 to provide a base level of expenditure in 2014-2016.

1.24 We then looked at adding to this base level of expenditure items which have been identified by FE as being a justified extra expenditure required in the years 2014-2016. We were not convinced by the justification for expenditure in some areas and therefore some items have been excluded from the recommended allowances.

1.25 This section will provide additional information on the model, including the principles and assumptions upon which it is based. This section also provides detail on the costs which have been excluded to create the baseline costs and the analysis of the costs which are to be added back for 2014-2016

Analysis model

1.26 FE's reported maintenance costs and forecasts have been reviewed and items have been separated out that are considered to be exceptional. This creates baseline maintenance costs.

1.27 The model then uses customer numbers as a primary driver to roll forward the base level expenditure into the forecast years.

1.28 The model is based on the following principles and assumptions:

- Actual Maintenance costs for 2011 provide the basis for the model (assessed in conjunction with the costs reported in 2010 and 2011).
- Using detailed information provided by PNGL[73] the model has been developed to allocate a cost of maintenance for each I&C customer. A further cost for every domestic customer has been included within the model set at a rate of 47% of the rate set for I&C customers. These rates are set such that the model produces the same actuals for 2010 & 2011 that have been reported by FE (excluding exceptional costs).

Actual Costs Excluded for Baseline

1.29 Along with Rune, we reviewed the actual costs incurred in 2010 & 2011 and made an assessment of which costs were considered exceptional items and would not be rolled forward into the baseline maintenance. These costs are listed in the table below.

Table 3 – Establishing the Base Maintenance Costs for FE

Cost element (£)	FE Actuals	
	2010	2011
Actual Maintenance Costs	**211,966**	**323,068**
Excluded from Base Costs	**9,821**	**103,456**
Exceptional PPE	0	0
PRS Overhauls	932	11,301
Meter Fault Software	0	0
DRD Works	817	16,269
Meter Keys	4,456	0
Third Party Investigations	0	7,522
Consultancy	0	37,619
firmuscare Pilot	0	20,638
LPG Site Prep	0	5,386
Meter Reading	2,018	1,416
SWR:Meter Exchanges	0	0
Other Site Works	1,599	2,366
Bridge Survey & Inspections	0	939
B6 Reg. Replacement	0	0
Established Base Costs	**202,145**	**219,612**

[73] PNGL Data was used due to the lack of detailed information provided by FE, following the consultation report FE confirmed that they did not capture costs in a manner to provide this detail.

Source: FE and the Utility Regulator

Assessment of Exception Items in Forecast

1.30 Following the establishment of the base maintenance costs using the model described above we then considered which forecast exceptional items should be added back on top of the base costs. We considered that sufficient justification was not provided for some items and therefore they have been excluded from the recommended allowance.

1.31 The adjustments to the added back costs have been developed on the following basis.

• Exceptional PPE	FE request costs relating to PPE each year, however they included an additional level of expenditure of £19k for PPE Clothing & Equipment in 2014. Having reviewed the case made by FE we are not convinced that special provision should be made for these exceptional costs in 2014 on top of the PPE costs included in the base maintenance allowance.
• PRS Overhauls	Costs of PRS major overhauls carried out 5 year intervals which were not incurred historically and, therefore, not included in base maintenance costs however we accept that these will be required in the GD14 period.
• Meter Reading	We consider meter reading to be predominately a supply related activity, however we note that the distribution company does have an obligation under the Network Code to provide some meter readings. We have therefore granted an allowance of £1k per annum.
• SWR: Meter Exchanges	FE submitted a request for additional allowances for domestic credit to prepay meter exchanges. This is a new cost are that was not included in FE submission at the time of the draft determination. Under the FE connection policy, meter exchanges from credit to prepay are free of charge to the customer, therefore we have granted an allowance under this price control. However we analysed FE's cost submission and note that they included costs for a new meter with each exchange. These exchanges are not a result of meter failure and therefore we expect FE to be able to reuse the meters that have been replaced. We have therefore removed the meter cost before granting the allowance for this cost area.
• Other Site Works	Following the draft determination, FE provided limited information to justify the submission. We

	have therefore granted an allowance based on historical costs rolled forward for the final determination.
• Bridge Survey and Inspections	Following the draft determination, detailed information was received from FE to justify the forecast costs. We have therefore updated the allowance to grant the full request in this area.
• B6 Regulator replacement	Additional has been provided by FE to justify an allowance in 2016 to cover inspections, however we not agree that the approach should be automatic replacement of B6 regulators at a 10 year frequency and therefore we have granted £21k in 2016.
• Leakage survey and Valve Inspection	Additional information has been provided by FE to justify the activities. We have determined an allowance of £32k per annum. The allowance is based on £12k per annum for valve inspections and maintenance (based on 2012 actual costs) plus £20k per annum to cover the leakage survey costs.
• PAYG Battery Replacement	The unit cost at £100/battery change is considered excessive has been reduced to £50 and the volume has been reduced to 100 units (installed in 2006 as previously advised by FE)
• Boiler Servicing • Provision for firmuscare customers	In addition to the exceptional items listed in the table above, FE also requested costs relating to boiler servicing and provision for firmuscare customers. These costs are related to supply activities and therefore FE has incorrectly allocated these costs to the distribution business in the historic actual costs and in the requested allowances for GD14.

1.32 The resulting costs for the assessment of exceptional items are given in the following table. This table also shows the determined maintenance costs .

Table 4 – FE Maintenance Added Back Costs

Cost element (£)	FE Submission			Final Determination		
	2014	2015	2016	2014	2015	2016
FE Submitted Base Cost	**205,692**	**212,325**	**215,163**			
Modelled Base Cost				**212,272**	**212,618**	**212,939**
Exceptional Items Added Back	**166,050**	**146,188**	**221,118**	**105,797**	**100,706**	**125,333**
Exceptional PPE	19,000	0	0	0	0	0
PRS Overhauls	45,933	39,300	36,462	45,933	39,300	36,462
Meter Reading	8,030	9,349	10,587	1,000	1,000	1,000
SWR:Meter Exchanges	25,587	30,039	34,269	8,864	10,406	11,871
Other Site Works	4,500	4,500	4,500	2,000	2,000	2,000
Bridge Survey & Inspections	16,000	16,000	16,000	16,000	16,000	16,000
B6 Reg. Replacement	0	0	40,000	0	0	21,000
Leakage Survey & Valve Inspection	47,000	47,000	47,000	32,000	32,000	32,000
PAYG Battery Replacement	0	0	32,300	0	0	5,000
Total Maintenance	**371,742**	**358,513**	**436,281**	**318,069**	**313,324**	**338,272**

Source: FE and the Utility Regulator

APPENDIX 4
Capital expenditure analysis for PNGL and FE

1.1 As stated in the main body of this report, we commissioned Rune Associates (Rune) to examine the capital expenditure programme of PNGL and FE and provide advice on efficient allowances that we should grant over this price control period. The text below details how the analysis was completed.

1.2 All allowances referred to in this chapter are pre-efficiency, unless explicitly stated otherwise

Basket of Work Approach

1.3 In their submissions, PNGL and FE provided a build-up of the estimated capex costs, which included breakdowns for the following items:

- Mains
- Pressure Reduction;
- Services;
- Meters; and
- Other capex.

1.4 To facilitate comparison between PNGL, FE and similar gas distribution networks in Great Britain where the split between these categories of work and expenditure differs, we adopted an analysis technique which combines the areas of expenditure into a "basket of work". The basket of work can then be analysed and compared between benchmarks according to the volume of each work category. This technique builds upon principles which have been used for Ofgem analysis for both GDPRC1 and RIIO-GD1 price controls. The key steps in the process are:

- Identify the items of work contained within the basket
- Select a standard set of unit rates to be used for each of these items
- Identify the workloads and associated costs submitted by the companies for these items
- Calculate the product of the company workload and the standard unit rate for each work item
- Rescale these for each work item so that the total cost equals the company's submission
- Establish an efficient level of performance for the basket of items in the most recent year for which actual information is available
- Calculate the efficient level of performance for each of the work items in that year
- Select assumptions for expected efficiency savings and price effects (see section 14 of the final determination).

1.5 Within the basket of work the costs and workloads for the following items of work have been included:

- Mains;
- Services; and
- Meters;

1.6 We have excluded 7 Bar Mains and Pressure Reduction Installations from the basket and they will be considered separately.

1.7 The technique involved assigning a typical cost value for each unit of work and using these to compare the companies' performance on a consistent basis. These units have been used by Ofgem for both GDPRC1 and RIIO-GD1. Whilst these are appropriate for comparison with GB gas distribution networks (GDNs), for the purposes of GD14, values have also been included to reflect the additional activities of providing and installing meters and associated regulators which are undertaken by the Northern Ireland networks.

1.8 In carrying out the analysis an assumption was made regarding the element of cost which is fixed, i.e. not dependent on the level of workload carried out. We explored the sensitivity of their analysis to this assumption and have concluded that the level of fixed costs assumed does not have a material impact on the assessment given the relatively close match between the workload levels between PNGL & FE. The analysis has been carried out using a level of 5% of the average costs of the two companies in 2011 which equates to £599k.

1.9 A set of standard unit rates have been used in the analysis. These rates have been set to reflect the typical costs reported by the NI gas distribution companies whilst keeping the ratios used by Ofgem in previous prices controls to compare GB networks. Rune has had to add to this list rates for meter costs which are not part of the GB networks workloads

Change to Approach for Final Determination

1.10 For the draft determination, we carried out a review of capex performance using a high level or broad set of work activities of the type which are used by Ofgem for benchmarking the GB network's new gas connections activities. Following the responses to the draft determination we reviewed this approach to identify if it would be more appropriate to use narrower, more specific work activities.

1.11 This review concluded that there are material differences in the nature of the work activities between the two companies which if not considered would distort the performance assessment of the companies. We therefore concluded that the benchmarking assessment methodology would be switched to using more specific work activities. The table below shows a comparison between the broad and narrow work activity categories.

Table 1 – Benchmark Categories

Activity	Benchmark Category		
	Broad	Narrow	
New Build Mains	<=180mm	32mm	90mm
		50mm	125mm
		63mm	180mm
		75mm	
	>180mm	200mm	355mm
		250mm	450mm
		315mm	
Other Mains	<=180mm	32mm	90mm
		50mm	125mm
		63mm	180mm
		75mm	
	>180mm	200mm	355mm
		250mm	450mm
		315mm	
New Build Domestic Services	Service	Service	
Existing Domestic Services	Service	Service	
I&C Services	Small (<=U40)	Very Small (U6)	Small (U16-U40)
	Large (>U40)	Medium (U65-U160)	Large (U250-U2500)
Domestic Meters	Meter	Meter	
I&C Meters	Small (<=U40)	U6	U25
		U16	U40
	Large (>U40)	U65	U650
		U100	U1000
		U160	U1600
		U250	U2500
		U400	

Source: Rune Associates

1.12 Moving to this more specific categorisation of the different work type undertaken results in the benchmarking assessment giving a much closer fit to the assessments made and costs actually incurred in carrying out the work.

1.13 We believe the additional information which is required for these more specific categories is not disproportionate in the data gathering exercise compared to the benefits and we have therefore accepted the recommendation to move to this form of assessment.

1.14 Further, we believe there are additional benefits to setting allowances based on these categories as such a move will;

- Ensure allowances are more closely matched to actual costs incurred
- Remove the need to set blended rates based upon forecast volumes
- Facilitate future benchmarking

PNGL/FE Performance Comparison

1.15 The major comparison which has been used to form the basis of the recommendations is a direct comparison of PNGL's and FE's actual reported costs in 2011.

1.16 The principal assumption used in the comparison and the resulting recommendation is that the unit rates for both NI companies should be approximately the same unless specific evidence is available to demonstrate material underlying cost differences.

1.17 The reported unit costs would suggest significant differences in some cases, for example on the provision and installation of domestic meters. We have attempted to understand this difference although we believe the primary cause is the allocation of costs between meter and service installation, a view endorsed by the companies. Our analysis has therefore attempted to minimise the impact such reporting inconsistencies can introduce.

1.18 Our determined allowances are based upon an assessment of efficiency in 2011 and rolling forward this performance to the years 2014-2016 using the forecast workloads.

1.19 The above methodology has been used to determine capital allowances at total level and for each cost item. The total capex allowance is consistent with the comparative efficiency analysis but, some of the outcomes at cost item level may appear to offer allowances that are greater than those requested or that are significantly lower. This occurs as a result of the restatement of costs to enable comparison between the NI companies and the assumption that the unit costs of both of these companies should be similar.

1.20 The application of the fixed cost assumption does result in some differences in unit rates between the companies for the same activity; this is due to differences between the companies in the levels of workload across which the fixed costs are apportioned.

1.21 The following tables relate to PNGL and show:

- Table 2: Comparison of workload forecasts as submitted by PNGL with the determined workload;
- Table 3: Comparison of unit rates per activity as submitted by PNGL, the Restated unit rates to enable direct comparison and our determined unit rates;
- Table 4: Comparison of PNGL's requested allowances based on the unit rates, the restated allowances to enable direct comparison and our determined allowances

Table 2 – PNGL Workload for Basket of Work Items

Cost Item £k	PNGL Submission				Final Determination		
	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	11,878	25,244	28,056	30,311	13,570	15,045	16,225
Other mains	53,307	42,012	42,363	42,643	26,203	26,203	26,203
Domestic services	9,322	8,400	8,250	8,050	9,800	10,050	10,250
Domestic meters	8,193	8,400	8,250	8,050	9,800	10,050	10,250
I&C Services	446	378	378	378	378	378	378
I&C meters	446	378	378	378	378	378	378

Source: PNGL & Rune Associates

Table 3 – PNGL Unit Rates for Basket of Work Items

Average Unit Rates	PNGL Submission £				PNGL Restated Submission £				Final Determination £		
	2009-11	2014	2015	2016	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	55	60	59	59	52	58	58	59	56	56	56
Other mains	61	56	56	55	67	71	71	71	68	68	68
Domestic services	523	567	568	567	570	621	614	606	609	603	599
Domestic meters	288	299	301	303	208	229	231	232	220	220	220
I&C Services	1,599	2,070	2,086	2,094	1,469	1,019	1,025	1,030	980	980	980
I&C meters	661	559	563	565	678	539	542	545	518	518	518

Source: PNGL & Rune Associates

Table 4 – PNGL Determined Allowances for Basket of Work Items – Based on Unit Rates

	PNGL Submission £k				PNGL Restated Submission £k				Final Determination £k		
	2009-11	2014	2015	2016	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	658	1,505	1,656	1,780	618	1,462	1,635	1,775	760	842	908
Other mains	3,266	2,358	2,354	2,358	3,573	2,967	3,010	3,045	1,788	1,788	1,788
Domestic services	4,878	4,762	4,686	4,567	5,318	5,216	5,063	4,882	5,969	6,064	6,140
Domestic meters	2,358	2,510	2,487	2,441	1,702	1,924	1,902	1,865	2,156	2,211	2,255
I&C Services	714	783	789	792	656	385	388	390	370	370	370
I&C meters	295	533	537	540	303	496	511	521	518	518	518
Totals	12,169	12,450	12,509	12,477	12,169	12,450	12,509	12,477	11,562	11,794	11,979

Source: PNGL & Rune Associates

1.22 The following tables relate to FE and show:

- Table 5: Comparison of workload forecasts as submitted by FE with the determined workload;
- Table 6: Comparison of unit rates per activity as submitted by FE, the Restated unit rates to enable direct comparison and our determined unit rates

- Table 7: Comparison of FE's requested allowances based on the unit rates, the Restated allowances to enable direct comparison and our determined allowances

Table 5 – FE Workload for Basket of Work Items

Cost Item £k	FE Submission				Final Determination		
	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	10,812	14,480	14,480	14,480	14,480	14,480	14,480
Other mains	81,977	72,494	56,504	48,704	72,494	56,504	48,704
Domestic services	2,371	4,000	4,000	3,800	4,000	4,000	3,800
Domestic meters	2,407	4,000	4,000	3,800	4,000	4,000	3,800
I&C Services	275	152	102	52	152	102	52
I&C meters	271	152	102	52	152	102	52

Source: FE & Rune Associates

Table 6 – FE Unit Rates for Basket of Work Items

	FE Submission £				FE Restated Submission £				Final Determination £		
	2009-11	2014	2015	2016	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	50	45	46	46	61	75	75	73	58	58	58
Other mains	79	100	98	98	84	103	100	98	79	77	78
Domestic services	759	934	947	938	651	826	823	798	634	634	631
Domestic meters	180	198	201	199	236	294	293	285	226	226	226
I&C Services	2,315	4,433	4,527	4,576	1,671	1,436	1,441	1,430	1,153	1,129	1,078
I&C meters	1,985	1,413	1,481	1,606	1,189	779	789	803	818	735	616

Source: FE & Rune Associates

Table 7 – FE Determined Allowances for Basket of Work Items – Based on Unit Rates

	FE Submission £k				FE Restated Submission £k				Final Determination £k		
	2009-11	2014	2015	2016	2009-11	2014	2015	2016	2014	2015	2016
New build housing mains	544	655	665	659	664	1,084	1,080	1,051	833	833	833
Other mains	6,465	7,274	5,533	4,771	6,857	7,446	5,633	4,791	5,698	4,327	3,779
Domestic services	1,799	3,736	3,790	3,566	1,544	3,306	3,293	3,031	2,537	2,537	2,398
Domestic meters	432	793	805	755	568	1,176	1,171	1,084	904	904	859
I&C Services	636	674	462	238	459	218	147	74	175	115	56
I&C meters	538	215	151	84	322	118	80	42	124	75	32
Totals	10,414	13,348	11,405	10,073	10,414	13,348	11,405	10,073	10,271	8,790	7,956

Source: FE & Rune Associates

PNGL Detailed Capex Tables

1.23 The following tables set out the detailed results of the capex analysis at individual pipe size and I&C meter size basis that are summarised in section 7 of this paper.

Table 8 – New Build Housing Mains

PNGL New Build Housing Mains Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
32mm	*50*	1,761	88,043	1,952	97,613	2,105	105,269
50mm	*53*	128	6,783	142	7,520	153	8,110
63mm	*55*	9,328	513,040	10,342	568,805	11,153	613,418
75mm	*57*	15	827	16	917	17	989
90mm	*60*	1,095	65,719	1,214	72,862	1,310	78,577
125mm	*67*	1,114	74,658	1,235	82,773	1,332	89,265
180mm	*82*	129	10,581	143	11,731	154	12,652
200mm	*88*	0	0	0	0	0	0
250mm	*105*	0	0	0	0	0	0
315mm	*132*	0	0	0	0	0	0
355mm	*151*	0	0	0	0	0	0
450mm	*203*	0	*0*	0	*0*	0	*0*
Totals		**13,570**	**759,651**	**15,045**	**842,222**	**16,225**	**908,278**

Source: PNGL & Rune Associates

Table 9 – Other Mains

PNGL Other Mains Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost	Number	Cost	Number	Cost
32mm	*61*	3,400	207,408	3,400	207,408	3,400	207,408
50mm	*64*	247	15,815	247	15,815	247	15,815
63mm	*67*	18,012	1,206,803	18,012	1,206,803	18,012	1,206,803
75mm	*69*	28	1,934	28	1,934	28	1,934
90mm	*73*	2,115	154,395	2,115	154,395	2,115	154,395
125mm	*82*	2,152	176,436	2,152	176,436	2,152	176,436
180mm	*100*	249	24,917	249	24,917	249	24,917
200mm	*107*	0	0	0	0	0	0
250mm	*129*	0	0	0	0	0	0
315mm	*161*	0	0	0	0	0	0
355mm	*184*	0	0	0	0	0	0
450mm	*247*	0	*0*	0	*0*	0	*0*
Totals		**26,203**	**1,787,709**	**26,203**	**1,787,709**	**26,203**	**1,787,709**

Source: PNGL & Rune Associates

Table 10 – I&C Services

PNGL I&C Service Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
Very Small (U6)	*680*	165	112,200	165	112,200	165	112,200
Small (U16-U40)	*1,062*	179	190,098	179	190,098	179	190,098
Medium (U65-U160)	*1,752*	30	52,560	30	52,560	30	52,560
Large (U250-U650)	*3,907*	4	15,628	4	15,628	4	15,628
Totals		378	370,486	378	370,486	378	370,486

Source: PNGL & Rune Associates

Table 11 – New I&C Meters

PNGL New I&C Meter Type	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
U6	*220*	165	36,300	165	36,300	165	36,300
U16	*483*	100	48,300	100	48,300	100	48,300
U25	*570*	53	30,210	53	30,210	53	30,210
U40	*808*	26	21,008	26	21,008	26	21,008
U65	*1,111*	19	21,109	19	21,109	19	21,109
U100	*1,566*	6	9,396	6	9,396	6	9,396
U160	*2,335*	5	11,675	5	11,675	5	11,675
U250	*3,505*	2	7,010	2	7,010	2	7,010
U400	*5,455*	2	10,910	2	10,910	2	10,910
U650	*8,834*	0	0	0	0	0	0
U1000	*13,427*	0	0	0	0	0	0
U1600	*21,399*	0	0	0	0	0	0
U2500	*33,043*	0	0	0	0	0	0
Totals		378	195,918	378	195,918	378	195,918

Source: PNGL & Rune Associates

Table 12 – Replacement I&C Meters

PNGL Replacement I&C Meter Type	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
U6	220	0	0	0	0	0	0
U16	483	0	0	0	0	0	0
U25	570	0	0	0	0	0	0
U40	808	9	7,272	77	62,216	51	41,208
U65	1,111	25	27,775	64	71,104	37	41,107
U100	1,566	21	32,886	32	50,112	32	50,112
U160	2,335	13	30,355	25	58,375	10	23,350
U250	3,505	7	24,535	11	38,555	8	28,040
U400	5,458	13	70,954	5	27,290	0	0
U650	8,837	7	61,859	1	8,837	5	44,185
U1000	13,420	0	0	1	13,420	1	13,420
U1600	21,399	0	0	0	0	0	0
U2500	33,054	1	33,054	1	33,054	0	0
Totals		96	288,690	217	362,963	144	241,422

Source: PNGL & Rune Associates

FE Detailed Capex Tables

1.24 The following tables set out the detailed results of the capex analysis at individual pipe size and I&C meter size basis that are summarised in section 8 of this paper.

Table 13 – New Build Housing Main

FE New Build Housing Mains Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
32mm	*51*	0	0	0	0	0	0
50mm	*54*	0	0	0	0	0	0
63mm	*56*	10,136	567,616	10,136	567,616	10,136	567,616
75mm	*58*	0	0	0	0	0	0
90mm	*61*	4,344	264,984	4,344	264,984	4,344	264,984
125mm	*69*	0	0	0	0	0	0
180mm	*84*	0	0	0	0	0	0
200mm	*90*	0	0	0	0	0	0
250mm	*108*	0	0	0	0	0	0
315mm	*135*	0	0	0	0	0	0
355mm	*154*	0	0	0	0	0	0
450mm	*207*	0	*0*	0	*0*	0	*0*
Totals		14,480	832,600	14,480	832,600	14,480	832,600

Source: FE & Rune Associates

Table 14 – Other Mains

FE Other Mains Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost	Number	Cost	Number	Cost
32mm	*62*	0	0	0	0	0	0
50mm	*66*	0	0	0	0	0	0
63mm	*68*	30,473	2,072,189	27,296	1,856,132	22,356	1,520,212
75mm	*71*	0	0	0	0	0	0
90mm	*74*	20,900	1,546,592	16,557	1,225,219	13,697	1,013,579
125mm	*84*	9,247	776,781	5,539	465,277	5,539	465,277
180mm	*102*	8,822	899,843	5,284	538,990	5,284	538,990
200mm	*110*	0	0	0	0	0	0
250mm	*131*	3,022	395,905	1,810	237,140	1,810	237,140
315mm	*165*	0	0	0	0	0	0
355mm	*188*	7	1,339	5	885	4	793
450mm	*253*	22	*5,581*	13	*3,230*	13	*3,355*
Totals		72,494	5,698,230	56,504	4,326,873	48,704	3,779,345

Source: FE & Rune Associates

Table 15 – I&C Services

FE I&C Service Size	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
Very Small (U6)	*694*	50	34,700	34	23,596	19	13,186
Small (U16-U40)	*1,084*	78	84,552	52	56,368	26	28,184
Medium (U65-U160)	*1,788*	18	32,184	13	23,244	6	10,728
Large (U250-U650)	*3,982*	6	23,892	3	11,946	1	3,982
Totals		152	175,328	102	115,154	52	56,080

Source: FE & Rune Associates

Table 16 – New I&C Meters

FE New I&C Meter Type	Allowed Unit Rate £	2014		2015		2016	
		Number	Cost £	Number	Cost £	Number	Cost £
U6	*225*	50	11,250	34	7,650	19	4,275
U16	*493*	39	19,227	26	12,818	13	6,409
U25	*581*	24	13,944	16	9,296	8	4,648
U40	*825*	15	12,375	10	8,250	5	4,125
U65	*1,135*	7	7,945	5	5,675	3	3,405
U100	*1,598*	7	11,186	5	7,990	2	3,196
U160	*2,383*	4	9,532	3	7,149	1	2,383
U250	*3,578*	3	10,734	2	7,156	1	3,578
U400	*5,534*	1	5,534	0	0	0	0
U650	*9,006*	1	9,006	1	9,006	0	0
U1000	*13,621*	1	13,621	0	0	0	0
U1600	*21,901*	0	0	0	0	0	0
U2500	*33,818*	0	0	0	0	0	0
Totals		152	124,354	102	74,990	52	32,019

Source: FE & Rune Associates

APPENDIX 5
Overview of Responses to Draft Determination

1.1 We have summarised the principal points made in each of the responses to the draft determination. Our response in turn to each of these is published on our website in a separate document at: http://www.uregni.gov.uk/uploads/publications/2013-12-20_GD14_Final_Determination_Appendix_5_-Responses_to_Responses.pdf

1.2 We have also published each of the responses to the draft determination and these are available at the following links:

Phoenix Natural Gas Limited	http://www.uregni.gov.uk/uploads/publications/PNGL_-_Response_to_GD14Draft_Determination.pdf
firmus energy	http://www.uregni.gov.uk/uploads/publications/FE_-_Response_to_GD14_Draft_Determination.pdf
The Consumer Council	http://www.uregni.gov.uk/uploads/publications/CCNI_-_Response_to_GD14_Draft_Determination.pdf
Airtricity Gas Supply Northern Ireland Ltd	http://www.uregni.gov.uk/uploads/publications/Airtricity_-_Response_to_GD14_Draft_Determination.pdf
Energy Saving Trust	http://www.uregni.gov.uk/uploads/publications/Energy_Saving_Trust_-_Response_to_GD14_Draft_Determination.pdf
Major Energy Users' Council	http://www.uregni.gov.uk/uploads/publications/Major_Energy_Users_Council_-_Response_to_GD14_Draft_Determination.pdf
National Energy Action NI	http://www.uregni.gov.uk/uploads/publications/NEA_-_Response_to_GD14_Draft_Determination.pdf