



Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

**Decision on October 2012 to September 2017  
distribution revenue for Bord Gáis Networks**

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*The Commission for Energy Regulation,  
The Exchange,  
Belgard Square North,  
Tallaght,  
Dublin 24.*

[www.cer.ie](http://www.cer.ie)

**Abstract:**

This paper sets out the CER's decision on the revenue that Bord Gáis Networks are allowed to recover from its customers over the period October 2012 to September 2017 to cover its costs associated with the gas distribution network in Ireland.

**Target Audience:**

This decision paper is for the attention of all members of the public and the energy industry. It will be of particular interest to parties that directly pay gas distribution network charges to Bord Gáis Networks and end-user customers to whom these charges are passed on.

**Related Documents:**

CER/11/070	Information Paper on scope of this review
CER/12/057	Consultation on BGN Distribution Revenue for PC3
CER/12/057a	CEPA Report on BGN Distribution on Opex and Capex for PC3
CER/12/057b	CER Model on BGN PC3 Distribution Revenue
CER/12/058c	Oxera Report on cost of capital
CER/12/057d	CEPA report on outputs and incentives
CER/12/198	PC3 Consultation Response Document
CER/12/196	Decision on October 2012 to September 2017 transmission revenue for Bord Gáis Networks

## Executive Summary

The Commission for Energy Regulation (the 'CER') is the independent body responsible for regulating the natural gas and electricity sectors in Ireland. Part of its responsibilities involves regulating the level of revenue which Bord Gáis Networks can recover from its customers to cover its costs. The CER's main goal in this area is to protect the current and future interests of consumers, while ensuring a stable environment for investors.

### **Process:**

On the 22<sup>nd</sup> May, the CER published a consultation document outlining its position and calling for public comment. The CER also acknowledged that further interaction with BGN and other stakeholders was expected to take place during the consultation phase and depending upon the outcome of the consultation process, it was possible that there might be adjustments in the revenues outlined in the consultation document. This decision is the final stage in the process of setting BGN's distribution revenues for the period October 2012 to September 2017 (known as PC3).

### **Revenues:**

CER has decided to allow €996m to BGN for distribution over the period of PC3. BGN sought revenue within the range of €1,177m to €1,258m, based on its proposed WACC of between 6.49% to 7.75%, over the period. This includes an Opex request of €463m which BGN later revised downwards to €425m.

### **Tariffs:**

The decision<sup>1</sup> on gas distribution tariffs for 2012/2013 has already been published on the CER website and showed an increase of 10%. Given the expected gas demands CER's decision would lead to a 6% increase in commodity tariffs (10/11 monies) and a 1% increase in capacity tariffs for the 2013/14 tariff period.

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<sup>1</sup> Decision on gas Distribution tariffs 2012-13 [CER/12/144](#)

**WACC:**

The CER has set the WACC (Weighted Average Cost of Capital) at 6.39% pre tax real (up from 5.2% in PC2). Analysis of BGN's cost of capital was undertaken in one of the most severe economic downturns in recent decades. The financial crisis that started in 2007 has grown into concerns about the sustainability of governments' fiscal positions across the Eurozone. These developments have increased the costs of raising capital and, in some cases, have affected the availability and cost of finance for European companies operating in some countries. BGN will, however, need to continue to raise capital at market rates, given its refinancing requirements over PC3. Thus, the analysis and decision on cost of capital is particularly important at this time.

The CER, together with its advisers on this issue, carefully considered what the impact of these conditions will be on the cost of capital for BGN. Unfortunately, all the analysis suggests that current conditions have increased the cost of capital dramatically, which will have a significant impact on customer tariffs.<sup>2</sup> The CER obviously regrets this, but is statutorily bound to ensure that BGN can finance the efficient operation of the gas network which is crucial to maintaining secure and reliable supplies of both gas and electricity. In order to ensure that consumers do not have to pay for high costs of capital throughout the entire 5-year period the CER has taken the latest data available to re-calculate the WACC since the time the consultation document was published. As a result of the recent and continuing reduction in the yields of Irish Government Bonds the WACC has been reduced from the 6.7% estimated in the consultation document down to 6.39%.

The CER has included a trigger mechanism in the WACC whereby the allowed cost of capital is reviewed annually and adjusted if there are further significant changes in market conditions in Ireland. This aims to ensure that, if market rates

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<sup>2</sup> The detailed analysis supporting this is contained in the Oxera report accompanying the consultation document.

rise by a de minimus, the allowed cost of capital would be adjusted, providing BGN with a degree of protection against capital market risk. Conversely, should market rates fall, the benefits of lower financing costs would be passed through to consumers sooner than under the current regulatory regime in PC2. This mechanism has a floor and ceiling of 5.2% and 8.2% respectively.

**Review of October 2007 to September 2012 costs:**

There was a €188m variation between the allowed capital expenditure and the actual capital expenditure in PC2. This was driven to a large extent by the economic downturn. The return of unspent Capex has mitigated the effect in the rise in WACC.

**Review of PC2:**

The PC2 period saw a secure and reliable supply of gas to customers being maintained (despite two consecutive severe winters which led to more than one 1-in-50 event), the roll out of pre payment meters, the completion of the cast iron replacement programme with a resultant decrease in leak repairs, the delivery of an extensive business transformation programme, new town connections being progressed such that the connection has been completed or is near complete on 17 new towns. Customer performance standards have been met and exceeded. This has been recognised through numerous awards to the customer contact centre. Apart from new connections, where targets were not met due to the economic downturn, the distribution business met or exceeded its required deliverables for PC2.

**PC3 Capex:**

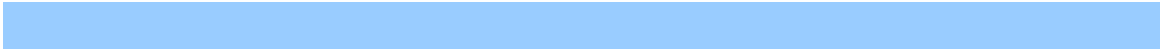
There are a number of large projects that are likely to arise during the course of PC3 but which have not yet received final approval. The Capex for these projects have not been included in the price control. Thus the capital requirements of gas smart metering have not been included at this time. A number of new towns are under consideration; again the capital requirements of these have not been included at this time.

**PC3 Opex:**

There are significant differences between BGN's request for operating expenditure and CER's final decision. CER recognises that delivering quality outputs for lower Opex allowances will be challenging, but is absolutely necessary given the difficult economic circumstances and the many challenges facing consumers.

In the context of the economic circumstances that Ireland finds itself in, CER takes the view that it is important that every available effort is made to reduce costs and deliver value for money to customers. These efforts to reduce costs must, however, be balanced against the requirements to deliver a reliable and safe service. Following the consultation process and taking on board comments from all parties, the CER has set what it believes to be a challenging, but appropriate Opex level for the PC3 period.

The Opex allowance set by the CER is €392m. This is €71m (15%) lower than the €463m originally requested by the distribution business for this period, and €33m (8%) lower than the €425m in BGN's revised submission.



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## **1.0 Introduction**

### **1.1 The Commission for Energy Regulation**

The Commission for Energy Regulation ('the CER') is the independent body responsible for overseeing the regulation of Ireland's electricity and gas sectors. The CER was initially established and granted regulatory powers over the electricity market under the Electricity Regulation Act, 1999. The enactment of the Gas (Interim) (Regulation) Act, 2002 expanded the CER's jurisdiction to include regulation of the natural gas market.

### **1.2 Purpose of this paper**

This decision paper sets out the CER's decision on the revenue that the distribution business<sup>3</sup> is to be allowed to recover from its customers over the period from October 2012 to September 2017 to allow it to finance its activities associated with owning and operating the gas distribution system in Ireland.

The purpose of this paper is to inform interested parties on these matters.

### **1.3 Structure of this paper**

The structure of this decision paper is outlined in this section:

- Section 1.0 details the purpose of this paper;
- Section 2.0 provides relevant background information. It also provides information on the CER's objectives and key assumptions;
- Section 3.0 outlines the process through which this review has been conducted to date;
- Section 4.0 provides information on how the Regulatory Asset Base (RAB) has been derived for the October 2012 to September 2017 period;
- Section 5.0 outlines a review of the distribution business's historic operational expenditure and performance for the October 2007 to September 2012 period;

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<sup>3</sup> The relevant elements of Bord Gáis Networks business are referred to within this paper as the 'distribution business'.

- Section 6.0 outlines the CER's decision on the transmission business's operational expenditure for the October 2012 to September 2017 period;
- Section 7.0 outlines the transmission business's historical capital expenditure for the October 2007 to September 2012 period;
- Section 8.0 outlines the CER's decision on the transmission business's forecast capital expenditure for the October 2012 to September 2017 period;
- Section 9.0 provides information on incentives for the October 2012 to September 2017 period;
- Section 10.0 provides information on the cost of capital for application to the distribution business's RAB over the October 2012 to September 2017 period;
- Section 11.0 describes the overall form of the price control, specifying the approach taken by the CER and how the base and subsequent year revenues have been determined: and,
- Section 12.0 provides a conclusion.

The consultation documents were previously published along with reports provided by two consultancy advisors engaged by the CER to assist with this project. These reports were:

- Three reports by Cambridge Economic Policy Consultants (CEPA)<sup>4</sup> providing recommendations on an appropriate level of operating and capital expenditure. The reports also covered appropriate incentive mechanisms; and,
- A report by Oxera on the appropriate cost of capital for Bord Gáis Networks.

A total of eleven consultation responses were received and each of these have also been published alongside this decision document. In addition, the CER have also published a document summarising the main issues raised in those responses and providing the CER's view on each of these.

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<sup>4</sup> In association with GL Noble and PKF.

## **2.0 Background, objectives & assumptions**

### **2.1 Introduction**

This section provides the following information:

- Relevant areas of the CER's role and the powers under which the CER makes its determination on the price control are outlined;
- The manner in which this price control follows on from previous controls is discussed;
- The CER's objectives for the September 2012 to October 2017 revenue control are detailed; and,
- The key assumptions underpinning the review have been documented.

### **2.2 The CER's role**

A general introduction to the CER is provided in Section 1.0 of this paper. The specific legislation under which the CER determines the distribution business's revenue and tariffs is detailed below.

Under Section 10A of the Gas Act 1976<sup>5</sup> (the 'Act') the CER may direct the distribution business on the basis for charges for transporting gas through the distribution system. In accordance with Section 10A of the Act, this decision paper outlines the CER's determination regarding the revenue that the distribution business will be allowed to recover from its customers during the period from October 2012 to September 2017.

The rationale for the CER's decision is explained in detail in the remainder of this paper.

### **2.3 Context of this revenue control**

This decision paper follows the consultation paper published on 22<sup>nd</sup> May, and sets out the CER's decision on the revenue that the gas distribution business to

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<sup>5</sup> S10A was originally inserted by the Energy Misc Provisions Act 1995 and was subsequently amended by the Gas Interim Regulation Act 2002, SI 426 of 2004, then SI 320 of 2005, then the Energy Misc. Prov Act 2006.

be allowed to recover from its customers over the period from September 2012 to October 2017. This also includes decisions on the incentives that the distribution business is to be subject to over that period. This is the third such revenue control for the distribution business to be set by the CER.

#### **PC1: October 2003 to September 2007**

The first multi-year year control covered the period from October 2003 to September 2007<sup>6</sup>. When setting this control the CER consulted on the regulatory principles and objectives, the appropriate form of regulation, and other issues related to the broad principles surrounding the form of the control prior to setting a control to cover a four year period.

This period saw strong growth in the number of new connections to the system, reflecting the growth in property development in Ireland and the desire to connect some properties that were not already connected.

At a general level, the distribution business's performance against the control was varied, with an underspend on capital expenditure and an overspend on operational expenditure.

#### **PC2: October 2007 to September 2012**

The second multi-year control covers the five year period from October 2007 to September 2012<sup>7</sup>.

This period saw completion of a replacement programme in which cast iron mains were converted to polyethylene (PE). While strong growth in new connections had been anticipated, this did not materialise.

This is also the first price control period during which there was full retail

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<sup>6</sup> The decision on the distribution business's revenue for the period October 2003 to September 2007 is available [here](#).

<sup>7</sup> The decision on the distribution business's revenue for the period October 2007 to September 2012 is available [here](#).

competition, which increases the importance of the distribution business's role as an independent system operator and in providing the infrastructure to facilitate retail competition. The period also saw moves towards more closely integrated all-Island energy markets, thereby increasing the importance for CER and the distribution business of taking into account developments in Northern Ireland.

The PC2 period also saw a secure and reliable supply of gas to customers being maintained (despite two consecutive severe winters which led to more than one 1-in-50 event), and the roll out of pre payment meters. The distribution business met and exceeded customer performance standards and this resulted in numerous awards to the customer contact centre.

### **PC3: October 2012 to September 2017**

The PC2 revenue control ended in September 2012. The next control period, PC3, covers the period from October 2012 to September 2017. Final decisions in relation to this control are contained in this paper. The objectives of PC3 are outlined in the following section.

## **2.4 Objectives for this revenue control**

The purpose of this review is to determine an appropriate level of allowed revenue for the distribution business over the next five years. When completing the review, the CER's objectives were to ensure that:

- The distribution business is able to maintain the distribution network to an adequate standard to meet customers' expectations;
- The interests of final customers are protected, in the short and long term, by containing tariffs to the maximum extent possible while delivering efficient network investment;
- The distribution business is able attract the necessary level of capital investment to support the approved level of capital expenditure. In doing so, the CER wants to ensure that the items of work included in the distribution business's investment plans are necessary and provide value for money for customers in terms of the benefits they add;
- Appropriate incentives are provided for the distribution business to improve its efficiency where possible and that as much as possible of

- these savings are passed through to consumers; and,
- The day-to-day intervention by the CER in the distribution business's work is kept to a minimum.

Section 3.0 of this paper provides information on the review process which the CER has undertaken in order to achieve the above objectives.

## **2.5 Definition of the 'distribution business'**

On the July 4<sup>th</sup> 2008, Gaslink assumed responsibility as the Transmission System Operator (TSO) and Distribution System Operator (DSO), responsible for operating, maintaining and developing Ireland's natural gas transmission and distribution systems. Gaslink was established under legislation as an independent subsidiary of Bord Gáis Éireann (BGÉ) to fulfill the requirements of EU Directives relating to the development of the natural gas market. On behalf of Gaslink, Bord Gáis Networks (BGN) constructs, extends and manages the day to day operation of the natural gas network in Ireland.

In order to comply with the unbundling provisions of the EU Third Package, the activities of BGN and Gaslink are to be amalgamated as an independent subsidiary of BGÉ as part of the implementation of an Independent Transmission Operator (ITO) model.

While the CER was mindful of Gaslink's fundamental role as transmission and distribution system operator, it also noted the importance of the revenue control to the gas transmission and distribution activities and the upcoming implementation of the ITO model. Therefore, when completing this revenue control BGN, as the forerunner to the ITO, was the CER's primary point of contact for all analysis.

In this decision paper the term 'distribution business' refers to the relevant sections of BGÉ which relate to ownership and operation of the gas distribution network. The term 'BGN' is used to refer to the combined transmission and distribution businesses.

## **2.6 Key assumptions for PC3**

Inevitably, given the five-year scope of the review, it has been necessary to make a number of assumptions regarding the environment within which the distribution business will operate for the price control period. The key assumptions made by the CER are as follows:

- There will be no substantial change in the functions of the distribution business; and,
- There will be no material changes in the circumstances within which the distribution business is operating, e.g. change of ownership.

A change to these assumptions may lead to a reopening of the revenue control.

## **2.7 PC2 outturn figures**

Within the consultation paper and this paper, the figures provided by the distribution business on its expenditure during the PC2 period have been labelled as actual or outturn values. This is not strictly correct, the values included for the October 2011 to September 2012 period were the distribution business's best estimate of the expenditure it would incur during that period.

The final values for 2011 October 2011 to September 2012 will be reviewed when these are available in 2013 and if necessary the revenue that the distribution business should be allowed to collect from its customers will be adjusted at that time to reflect the outcome of the review.

## **2.8 Tariff comparisons**

The decision on gas distribution tariffs 2012/2013 has already been published on the CER website and showed an increase of 10%. Given the expected gas demands CER's decision would lead to a 4% increase in commodity tariffs (10/11 monies) and a 1% decrease in capacity tariffs for the 2013/14 tariff period.

Please note that given the way the distribution tariff is calculated there would be different price rises for different customers based on annual consumption band and capacity and commodity split.

## **2.9 Summary**

The above sections provide some background to the objective of this control,

along with other relevant details and assumptions.

Changes in the assumption outlined in Section 2.6 may lead to a reopening of the revenue control.

## **3.0 The regulatory review process**

### **3.1 Introduction**

This section provides information on the process that led to the decisions outlined in this paper. It provides:

- A high level overview of the approach the CER has adopted to determining the revenue that the distribution business can recover from its customers during the period from October 2012 to September 2017;
- Information on how the project has been conducted to date;
- A summary of the expertise used; and,
- Information on the scope of this review.

### **3.2 Overview**

#### Review of historic capital expenditure

The capital expenditure incurred by the distribution business over the October 2006 to September 2012 period was reviewed. The appropriateness and efficiency of the investments made during that period were assessed. This analysis included an assessment of actual versus planned capital expenditure over the period, in terms of the volume of, unit cost of, and need for the investment.

#### Review of historic operational expenditure

The operational expenditure incurred by the distribution business over the October 2007 to September 2012 period was reviewed. This involved assessing improvements in efficiency made by the distribution business during that period and levels of network performance and customer service achieved.

#### Review of forecast capital expenditure

The capital expenditure which the distribution business forecasts it will incur during the October 2012 to September 2017 period was examined, with a particular focus on ensuring value for money.

#### Review of forecast operational expenditure

The operational expenditure which the distribution business forecasts it will incur during the October 2012 to September 2017 period was reviewed, with focus on ensuring value for money and efficiency improvements.

#### Determining the regulatory asset base

Following the above review of historic capital expenditure any variances between the approved and actual efficient expenditure were reflected by adjusting the asset base. The original asset base had been put in place as part of the first five-year review (October 2003 to September 2007) and adjusted for the second (October 2007 to September 2012).

The asset base was also adjusted to allow for forecast capital expenditure. This adjusted asset base is for use for the forthcoming review period (October 2012 to September 2017) and has been published alongside this paper.

#### Determining the appropriate cost of capital

The cost of capital for application to the distribution business's regulatory asset base has been developed.

#### Determining appropriate incentives

Using the reviews of the distribution business's historic and forecast performance as a basis, incentives have been developed for the forthcoming period.

These are broadly the same as the incentives in place for PC2.

#### Determining the allowed revenue

The output of the above analysis was fed through to develop revenue (which the distribution business will be able to recover from its customers) for each gas year within the period October 2012 to September 2017. This revenue will feed through into the setting of gas distribution tariffs for each tariff period.

### **3.3 Conduct of this project**

In order to ensure that there is clarity as to the underlying data and assumptions as well as the analysis itself, this project has involved a high level of interaction

with the network business. In addition, information on the review has previously been published for consultation. The high level steps associated with this process are provided here.

The first phase of public consultation was undertaken in April 2011, when the CER published an information note requesting comments on the proposed scope of its forthcoming gas transmission and distribution revenue reviews. Following receipt of comments, the CER published a response paper in September 2011<sup>8</sup>. Further detail on the content of that information note is provided below in Section 3.6.

In parallel with the above consultation the CER acquired consultancy support for the provision of technical and financial advice over the course of the project. Detail on this is provided in Section 3.4.

To ensure that the CER and its advisors attained an adequate understanding of the distribution business, the CER engaged with the network business to ensure that relevant data was provided in a useable format. A questionnaire was issued to the network business outlining the technical, economic and financial data required by the CER. The network business then completed the questionnaire in two stages: providing historic data first and then progressing to forecast information. The network business also provided a significant amount of supporting documentation. Following submission there was a period of interaction between the CER and the network business during which clarifications and further information were sought.

This interaction allowed the CER, with the assistance of its advisors, to complete a comprehensive review of the network business's historic and forecast performance, leading to the development of the proposals outlined in the consultation paper.

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<sup>8</sup> This information note, the comments received and the CER's response is available [here](#)..

### **3.4 The expertise used**

The CER has completed numerous reviews of regulated utilities since its foundation in 1999 and has developed its internal abilities over that period. To augment these skills, and reflecting the range of analysis required, the CER acquired the services of economic and engineering experts to assist in the review of the distribution business's historic and forecast costs and performance.

Cambridge Economic Policy Associates (CEPA) provided advice on the technical aspects of the review. This included reviewing the network business's capital and operational expenditure and providing advice on an efficient level which should be approved by the CER for recovery from the network business's customers. This role included completing the benchmarking studies necessary to provide relevant and well founded advice. It also involved the provision of advice on appropriate incentive arrangements.

Oxera provided advice on the financial aspects of the review. The main body of work completed by Oxera is the provision of advice on the appropriate cost of capital for the network business.

The advice put forward by the CER's consultancy support fed through into the proposals in the consultation paper and into the final decisions set out in this paper. The original reports provided by both CEPA and Oxera were published alongside the consultation paper.

### **3.5 Scope of this review**

The decisions outlined in this paper relate to the regulated aspects of the distribution business's activities. However, as part of the review process in reaching a final decision, the CER has also taken into account the allocation of some corporate centre costs and overheads to the regulated business units.

### **3.6 April 2011 information note<sup>8</sup>**

#### **3.6.1 Introduction**

As detailed above, this will be the third revenue control to be put in place for the

network business. The previous reviews allowed some treatments (for example, depreciation methodologies) to become established practice. As a result the CER stated its intent to continue using some of the methodologies established during the previous reviews, and to focus on other areas that would ensure that the distribution business is operated and developed in a cost-effective manner. In April 2011 an information note was published to this effect<sup>8</sup>. Section 3.6.2 provides a summary of the main points of that information note and the CER's response to comments received.

### **3.6.2 Summary of April 2011 information note**

In April 2011, the CER published an information note highlighting and requesting comments on some initial high level proposals regarding the upcoming review of the network business's performance and costs. The CER proposed that the project undertaken by the CER would focus on reviewing and setting the network business's:

- operating expenditure;
- capital expenditure;
- weighted average cost of capital (WACC);
- regulatory asset base (that is, adjusting for the level of expenditure incurred by the network business); and,
- performance incentives<sup>9</sup>.

The CER stated its view that focusing on the above areas would allow for the continued protection of gas customers by ensuring that the gas distribution network business was operated and developed to meet customer needs in a cost-effective and efficient manner.

The information note outlined the CER's proposal that, on the basis of regulatory certainty and maintaining regulatory precedent, certain methodologies which have become established during the previous control periods, would not be

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<sup>9</sup> The information note also referred to the examination of the appropriate regulatory treatment of the BGÉ Interconnectors. However, this has been dealt with through a separate consultation process.

reviewed as part of this project. These are as follows:

- The length of the control period would not be changed. That is, it would continue to be a multi-annual revenue review covering a 5 year period;
- The Capital Asset Pricing Model (CAPM) would continue to be used to aid the determination of a WACC which would be applied to the network business's regulatory asset base;
- The CPI-X model would continue to be used to set the level of revenue to be recovered by the network business; and,
- The existing methodologies used for valuation and depreciation of the business's assets would continue to be applied.

The CER also stated that it continued to believe that the revenue controls for the transmission and distribution businesses should be set using a common set of principles. However, in developing the controls for each business, the CER would take into account their specific features.

The CER noted that it would consider all submissions to that information paper and respond as appropriate in the relevant consultation papers. Comments were invited from stakeholders on the scope of the review and alternative methodologies that could be taken with respect to the currently adopted approaches listed above.

Following receipt of comments, the CER published a response paper in September 2011<sup>8</sup>. While the CER provided clarifications and was generally in agreement with the comments provided by the respondent, there were no changes to the CER views as outlined in the original information note. The CER also noted that the final decision on the matters outlined within the information note would be included within the final decision on the network business's revenue for the October 2012 to September 2017 period.

### **3.7 Consultation Document**

The CER published a consultation paper on 22<sup>nd</sup> May along with three reports from the consultants covering, Opex & Capex for PC3, Cost of Capital and a report on Outputs & Incentives. In addition the CER published the excel model

showing BGN's PC3 Distribution Revenue. The consultation document was published alongside the consultation on BGN Transmission Revenues for PC3 and respondents replied to one or both of the consultations. The consultation period closed on Monday, 9<sup>th</sup> July and a total of eleven responses were received, of which four specifically addressed the consultation on distribution revenue. These were as follows:

- Bord Gáis Networks
- Vayu
- ESB
- Irish Offshore Operators' Association

These responses raised a number of issues and the CER have reviewed these along with our consultants. A number of changes have been made to take on board certain comments made by respondents. The responses are published alongside this decision paper along with a consultation response document which summarises the main issues raised by respondents and provides the CER's response to each.

## **4.0 The Regulatory Asset Base**

### **4.1 Introduction**

The revenue that the distribution business recovers from its customers during each review period can be divided into three separate categories:

1. Revenue to cover the distribution business's operational costs during that period;
2. A return on capital on the distribution business's assets; and,
3. Revenue to cover depreciation of the distribution business's assets.

The Regulatory Asset Base (RAB) plays a key role in the determination of the amount of depreciation that the distribution business receives (item 3 above), and is the base to which the rate-of-return is applied when determining the return on capital for the distribution business (item 2 above).

This section provides information on a number of interrelated issues that determine the distribution business's RAB. Specifically, this section provides information on:

- where to find detail on the type of assets within the distribution business's RAB;
- the methodology used to value the assets within the distribution business's RAB;
- the length of asset lives applied to the assets within the distribution business's RAB;
- the depreciation methodology applied to the distribution business's RAB;
- the regulatory practice when an asset is physically replaced prior to being fully depreciated; and,
- the regulatory treatment of (1) clawback of revenue earned on assets that were not put in place and (2) additions to the distribution business's RAB

Finally, Section 4.9 provides a summary.

### **4.2 Composition of the RAB**

The RAB is documented within the final excel model which is published alongside this paper.

## **4.3 Valuation of the Regulatory Asset Base**

### **4.3.1 Introduction & continuation of current approach**

The preceding section provides information on where to find detail on the composition of the RAB. However, the approach to valuing the assets within the RAB is also an important decision within the revenue control process.

In the April 2011 information note the CER stated its intention to continue its current approach for valuation of the RAB through into the next review period. The information note stated that on the basis of regulatory certainty and maintaining regulatory precedent the methodology for valuation of the RAB, which has become established practice during the first two control periods, would not be reviewed as part of this project.

In the consultation document the CER restated its intention to continue with the current methodology for the valuation of the distribution business's RAB. The CER have maintained this methodology for the final decision, but in order to provide background information the following sections provide further information on this topic including alternatives.

### **4.3.2 Background**

The core issue regarding the valuation of the distribution business's RAB is whether the RAB should reflect the value of the assets now (replacement value) or when they were built (acquisition cost). A number of variations on these approaches are outlined below. The advantages and disadvantages of each are detailed in

Table 1 below:

#### **Acquisition cost**

Assets are valued at their original cost of construction /acquisition. The value of assets is not indexed for inflation nor is their value linked to the cost of replacement.

### **Replacement cost**

Assets are valued at what it would cost to replace existing assets. There are two approaches to replacement cost: indexing the acquisition cost of the assets; and revaluing the asset based using a modern equivalent asset (MEA) approach.

### **Replacement cost less stranded assets**

This is as per replacement cost (above) but those assets that are not utilised in the current system would be excluded. Effectively, this would be the cost of building a replacement system.

### **Deprival value**

The assets would be valued at the lower of their replacement cost or economic value (in the event that they could not be replaced).

Table 1: Advantages and disadvantages of valuation approaches

<b>Approach</b>	<b>Advantages</b>	<b>Disadvantages</b>
Acquisition cost	This is the simplest approach to valuing the RAB. It requires no adjustments to the RAB, other than for new capital expenditure and depreciation.	It does not reflect the economic values of the assets and therefore is likely to reduce incentives to invest in the network.

Replacement cost	<p>There are two variations of this:</p> <p><b>Modern Equivalent asset</b> This ensures the RAB is directly linked to the costs of constructing a new distribution system.</p> <p>It provides a better indication of changes in market values.</p> <p><b>Indexed acquisition cost</b> This is simpler to apply than MEA, as it does not require an in-depth review of the asset base.</p>	<p><b>Modern Equivalent asset</b> Complex, as in principle all assets within the RAB must be reviewed and valued.</p> <p>Assessment of networks used for valuation is controversial – specifically whether this should be the existing or an ‘optimal network’.</p> <p>This approach risks deterring new investment if some existing assets are stranded when the RAB is revalued.</p> <p><b>Indexed acquisition cost</b> Simple indexation means that some assets may be overvalued and some undervalued relative to their true market value. This may be worsened by retirement/disposal of some assets.</p> <p>It does not take into account technological improvements that increase capital efficiency.</p>
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Replacement cost less stranded assets	The advantages are as per those listed above for replacement cost. In addition, it has the benefit that any assets that are considered stranded – that is, where there is an unambiguous case that they are not required – would be removed from the RAB.	Identifying stranded assets is somewhat judgmental, particularly for the distribution system. It would need to be demonstrated that a specific asset should not have been built based on reasonable assumptions.  Excluding stranded assets from the RAB may deter investment. That is, the distribution business may not invest in some cases if there is a risk that the asset may become stranded, for example, through expected load not appearing.
Deprival value	Provides most accurate economic valuation of the network	Highly complex to apply as requires detailed modelling of system to determine asset values

Having balanced and considered all of the above, the CER decided that the distribution business's RAB would be valued using a replacement cost approach for the period October 2003 to September 2007. It was subsequently decided that the approach would be continued for the period October 2007 to September 2012.

While it is recognised that there are advantages and disadvantages associated with each methodology, the replacement cost approach was taken as it is more likely to result in the correct level of network investment.

As documented above there are a number of variations of replacement cost that could be used. The version used by the CER uses the acquisition cost, indexed with inflation, as a proxy for the replacement cost.

### **4.3.3 Decision**

While alternatives and a discussion are provided above the CER has decided not to change the current methodology.

The CER will continue to use this methodology to value the distribution business's asset base for the October 2012 to September 2017 period. Maintaining regulatory certainty by continuing this methodology, which has become established practice over the past two control periods, was a significant factor in the decision. However, it should also be noted that, if this was not a factor, the transparency and investment signals, etc. related to the current approach would still provide valid arguments for its continuation.

## **4.4 Asset Lives Applied to the RAB**

### **4.4.1 Introduction & decision to continue current approach**

The assets lives applied to assets within the RAB feeds through into the level of depreciation that the distribution business receives on those assets within each control period (or indeed year).

In the information note, the CER stated its intention to continue to use the asset lives that were previously employed. The CER is now confirming that this is the case.

### **4.4.2 Background**

When setting the revenue control for the October 2003 to September 2007 period, the CER did not make any changes to the existing economic life of distribution assets. Assets were grouped into seven main categories for depreciation periods, with straight line depreciation applied for all assets. This was continued for the October 2007 to September 2012 period, as shown in

Table 2 below:

**Table 2: Asset lives applied to distribution assets**

<b>Asset</b>	<b>PC1</b>	<b>PC2</b>	<b>PC3</b>
Pipelines/Above ground installations	60	60	60
Dublin cast iron	60	60	n/a
Cork cast iron	60	60	n/a
Meters	15	15	15
Land	40	40	40
Buildings	40	40	40
Equipment	5	5	5
ITO setup costs <sup>10</sup>	n/a	n/a	15

The CER sees no reason to change this treatment for the October 2012 to September 2017 period and has maintained the asset lives of the categories accordingly.

Please note that an additional category has been added within the above table for PC3. It has been decided that setup costs relating to the Independent Transmission Operator (ITO) will added to the asset base with an asset life of 15 years. This is discussed further in Section 7.5 of this paper.

The model published alongside this paper is generally in line with the above. However, in the case of Dublin and Cork cast iron an accelerated depreciation profile was agreed and incorporated into the model. This was due to these assets being subject to a replacement programme which mean that the assets' physical life was no longer consistent with the asset life included above in Table 2. More detail is provided in Section 4.6.

#### **4.4.3 Decision**

For the control period covering October 2012 to September 2017, the CER has decided to continue applying the assets lives used during PC2. These are

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<sup>10</sup> Independent Transmission Operator as discussed further below.

detailed above in Table 2. The CER does not consider that any new evidence has arisen during PC2 that would justify re-considering the asset lives used. The decision to depreciate ITO setup costs over 15 years is covered in more detail in Section 7.5.

## **4.5 Depreciation method**

### **4.5.1 Introduction & decision to continue current approach**

In the information note and subsequent consultation paper, the CER stated its intention to continue using the same depreciation methodology for the period October 2012 to September 2017 as was employed in PC2. The CER is now stating its decision to continue using straight line depreciation during the period October 2012 to September 2017.

The following sections provide further information on this topic.

### **4.5.2 Background**

Economic depreciation profiles allocate the original capital cost of a project over its useful life. There are a number of possible methods through which asset bases may be depreciated; common relevant examples are straight-line, sum-of-years-digits<sup>11</sup> and declining balance depreciation.

When setting the first revenue control, covering the period October 2003 to September 2007, the CER chose the straight-line method. Some of the benefits of this approach are as follows:

- Straight-line fully depreciates the assets over a period of time. The declining balance method does not as it is calculated as a portion of the declining value of the asset.
- Due to the nature of the design life of network assets and the load profile of the use of network assets, the straight-line method is considered to be a

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<sup>11</sup> This is considered more relevant/appropriate for industries with significant technical progress.

reasonable representation of economic depreciation for network assets. The CER noted that the straight-line approach is simple, transparent and objective and also noted that it was the approach that had been chosen for electricity networks.

The straight-line approach to depreciation was then continued when setting the second revenue control, covering the period October 2007 to September 2012.

#### **4.5.3 Decision**

For the control period covering October 2012 to September 2017, the CER will continue applying the straight-line method of depreciation used during PC2. Maintaining regulatory certainty by continuing this methodology was a factor in this decision. However, regulatory certainty aside, the rationale that led to this approach being chosen in the first instance would still provide relevant arguments for choosing straight-line depreciation for the forthcoming period.

#### **4.6 Replaced Assets/disposals**

During the PC2 period the CER agreed that for the cast iron replacement project, since these assets were being replaced prior to being fully depreciated on the RAB, these assets would be removed from the RAB in the year of replacement and the remaining indexed net book value would be provided to the distribution business over a shorter period than would otherwise have been the case. This treatment is reflected in the final model that is published alongside this paper.

Essentially there are two options that the CER considered: the distribution business could have been given the remaining net book value once the assets were replaced, or the assets could have remained on the RAB until they were fully depreciated (even though their replacements could also be on the RAB at that time).

In the consultation paper respondents were requested to provide their views on the appropriate treatment, including any alternatives to the above suggestions. Part of the reason for this was because it may become more relevant in the future if smart metering progresses and results in the replacement of meters prior

to them being fully depreciated on the RAB. Respondents did not express a preference on either of the two options set out by the CER. Having considered the matter further the CER has decided that these issues will be considered on a case by case basis.

#### **4.7 Capital expenditure approved but not incurred**

The CER has decided that revenue collected by the distribution business to cover return and depreciation on projects which were planned for the PC2 period and subsequently not put in place will be clawed back and netted off the revenue to be collected by the distribution business during the PC3 period. Adjustments to this revenue prior to it being returned to the network customer are discussed in Section 7.6.3.

In some cases the distribution business would be allowed to retain this revenue as part of an incentive mechanism to ensure only necessary assets are built.

The details of these calculations for PC2 are provided in Section 7.6.

The same methodology will be used for the look back at capital expenditure at the end of PC3.

#### **4.8 Additions to distribution business's RAB**

##### **4.8.1 Introduction & decision to continue current approaches**

The regulatory treatment of additions to the distribution business's RAB is an important issue in a revenue control. This section details the regulatory treatment to:

- Additions to the distribution business's RAB;
- Interest During Construction (IDC); and,
- Capital contributions and grants.

##### **4.8.2 Additions**

The majority of additions are made to the distribution asset base on an 'as spent' basis (that is, assets are capitalised when the expenditure is incurred). The

exceptions would include non pipe spend and new town spend. This is in contrast to the transmission asset base which reflects assets on an 'as capitalised' basis.

#### **4.8.3 Interest During Construction (IDC)**

The CER understands that since additions are made to the asset base on an 'as spent' basis, no interest during construction is included.

The CER has decided to continue this policy during the forthcoming revenue control period, covering October 2012 to September 2017.

#### **4.8.4 Capital contributions and grants**

In both the first and second revenue controls, any capital contributions and grants were subtracted from capital expenditure in the relevant year.

The CER has decided to continue this policy during the forthcoming revenue control period, covering October 2012 to September 2017.

### **4.9 Summary**

This section provides a summary of the CER's final decisions on a number of interrelated areas that impact on the setting of the distribution business's RAB and the level of revenue that the distribution business is allowed to collect during each control period (or year) to cover its depreciation costs.

No changes in methodology relative to that employed during the October 2007 to September 2012 period have been made for the October 2012 to September 2017 period.

#### Valuation methodology

The CER is to continue using the methodology employed during previous control periods. This is a variation of replacement cost approach, which uses the historic cost, indexed upwards to allow for inflation, as a proxy for replacement cost.

#### Asset lives

The CER is to continue using the methodology employed during previous

controls. Under this approach a life of 60 years is applied to network pipelines. These make up the majority of the distribution business's asset base. The lifetimes applied to other assets are detailed in Table 2 in Section 4.4 of this paper.

#### Depreciation methodology

The CER is to continue using the methodology employed during previous control periods. This is straight-line depreciation.

#### Depreciation and return on capital expenditure approved but not incurred

The CER's decision is that revenue collected by the distribution business to cover return and depreciation on projects which were planned for the 2007 to 2012 period and subsequently not put in place will be clawed back and netted off the revenue to be collected by the distribution business during the 2012 to 2017 period. Details of how this mechanism was implemented for PC2 are provided in Section 7.6.

## **5.0 Historical operational expenditure**

### **5.1 Introduction**

This section examines the historical operational expenditure (Opex) undertaken by the distribution business over the 1 October 2007 to 30 September 2012 period. The outturn expenditure<sup>12</sup> is assessed and compared to the revenue allowed by the CER as part of the PC2 determination.

This historical review of Opex is used to derive normalised costs that form the basis for PC3 Opex allowances.

The distribution business has under-spent overall and in each year with the exception of the forecast year (2011/12)<sup>12</sup>. However the principal area of under-spend against the allowance has been pass-through costs, primarily rates where there is an incentive for the distribution business via a 50:50 share with distribution business's customer in savings achieved. Total operating costs before Gaslink and pass-through charges shows an overspend against the allowance of €11.4m. This is offset by the distribution business's share of the surplus in the pass-through costs and there is no overall excess.

### **5.2 Objectives for the review of historic Opex**

The main objective of the review of the distribution business's historical Opex is to assess whether the distribution business's expenditure has been incurred efficiently while delivering the expected benefits for customers in line with the package agreed as part of the PC2 determination.

This review of historic performance also assisted in the CER's determination of the appropriate allowed Opex for the October 2012 to September 2017 period, as detailed within Section 6.0 of this paper.

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<sup>12</sup> As the time of completing this review the outturn costs for the October 2011 to September 2012 period were not available. Therefore, forecasts were used for that period.

### 5.3 Overview of historic operating expenditure

Table 3 below provides a high level summary of:

- the operational costs incurred by the distribution business during October 2007 to September 2012;
- the operational costs approved by the CER for that period; and,
- the variance between the two.

The narrative included within Sections 5.3.1 to 5.3.6 below provides more detail. Note that BGN has made a request for additional PC2 operational costs related to the ITO. This is not covered within the below table (as it was not envisaged at the time when the PC2 costs were approved), but is discussed below in Section 5.3.7.

**Table 3: Distribution operating costs over PC2 period**

2010/11 Monies €k	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Forecast	PC2 Total	PC2 Allowance	PC2 Variance
<b>Direct</b>								
Network Maintenance	19,790	19,639	17,855	22,584	21,681	101,549	94,649	- 6,900
New Business	1,973	1,997	1,998	2,159	2,074	10,200	8,815	-1,386
Support Activities	8,398	11,532	9,739	13,696	13,291	56,656	46,928	-9,729
<b>Sub-total Direct</b>	<b>30,161</b>	<b>33,168</b>	<b>29,590</b>	<b>38,439</b>	<b>37,046</b>	<b>168,404</b>	<b>150,391</b>	<b>-18,016</b>
Allocated Transportation Costs	11,963	16,256	15,607	16,967	18,049	78,842	92,607	13,765
Direct Transportation Costs	1,386	2,001	3,134	2,676	3,490	12,687	17,888	5,200
Support Activities	3,580	3,177	2,890	3,207	3,773	16,627	18,238	1,609
<b>Sub-total Business Support Services</b>	<b>16,929</b>	<b>21,434</b>	<b>21,631</b>	<b>22,850</b>	<b>25,312</b>	<b>108,155</b>	<b>128,732</b>	<b>20,574</b>
Miscellaneous Deductions/Charges	4,370	1,482	3,471	-2,548	7,218	13,993	0	-13,994
<b>Overall Total Direct</b>	<b>51,460</b>	<b>56,084</b>	<b>54,692</b>	<b>58,741</b>	<b>69,575</b>	<b>290,552</b>	<b>279,124</b>	<b>-11,435</b>
<b>Pass through total</b>	<b>15,114</b>	<b>13,764</b>	<b>11,844</b>	<b>15,519</b>	<b>19,252</b>	<b>75,493</b>	<b>99,623</b>	<b>24,131</b>
Gaslink ISO	506	620	653	578	689	3,046	3,200	154
<b>Grand Total</b>	<b>67,080</b>	<b>70,468</b>	<b>67,189</b>	<b>74,838</b>	<b>89,516</b>	<b>369,091</b>	<b>381,948</b>	<b>12,850</b>

#### 5.3.1 Direct Opex (allowed €150.4m, outturn €168.4m)

The distribution business reported its Distribution Direct Operating Expenditure (Opex) costs under the following key headings: (i) Network Maintenance; (ii) New

Business; and (iii) Support Activities. These are discussed below in turn

### **5.3.2 Breakdown of Direct Opex**

#### **Network maintenance** (allowed €94.6m; outturn €101.5m)

Network maintenance covers the direct operational activities that are undertaken by the distribution business to maintain the distribution network assets in a safe and fit-for-purpose condition.

In PC2, the CER approved an allowance of €94.6m for this activity. The distribution business's outturn costs were €101.5m, and overspend of €6.9m.

Some factors that contributed to this were an increase in reports of 'no gas' as a result of pre-payment meters running out of credit and increased costs due to the extreme weather conditions of 2009 and 2010.

The figures reported are net of any revenues collected through sitework charges, which cover a range of operational jobs relating to meters and services.

#### **New business** (allowed €8.8m; outturn €10.2m)

The two key activities within new business are the areas of the customer contact centre and market development.

In PC2, the CER approved an allowance of €8.8m for this activity. The distribution business's outturn costs were €10.2m, and overspend of €1.4m.

Call centre costs have increased due to an increase in call volumes over PC2. Customer satisfaction levels have improved.

Market development relates to the promotion of natural gas and new connections.

#### **Support activities** (allowed €46.9m; outturn €56.7m)

The key Opex activities within support activities are:

- Mayo/Galway Opex, which provides a level of emergency response cover

- following the expansion to the West of Ireland;
- Business Regulation and Planning;
  - General Management of the distribution business;
  - Meter Control and Instrumentation involves monitoring of remote pressure regulating installations and metering sites;
  - Radio Room which dispatches emergency response fitters in response to emergency calls;
  - Safety and Quality;
  - Sales and Service Support; and,
  - Stores

In PC2, the CER approved an allowance of €46.9m for this activity. The distribution business's outturn costs were €56.7m, an overspend of €9.7m.

The costs in the radio room area have been impacted by the increased number of 'no gas' calls for new prepayment meter customers. For sales and services support there has been a reduced level of customer contributions because of the economic downturn.

### **5.3.3 Business Support Services (allowed €128.7m; outturn €108.2m)**

This area covers transportation, financial management and commercial functions. This includes key areas of financial control, code compliance, market arrangements, commercial and regulatory compliance, meter reading and customer support.

In previous years transportation and shared services were allocated to the distribution business. As a result of the organisational changes in PC2 and the establishment of the ITO these services have become an integral part of BGN, but still need to be apportioned over the transmission, distribution and unregulated networks business within BGN.

In PC2, the CER approved an allowance of €128.7m for this activity. The

distribution business's outturn costs were €108.2m, an underspend of €20.6m<sup>13</sup>.

#### **5.3.4 Misc. deductions/charges (allowed €0m; outturn €14.0m)**

This area represents charges and credits relative to the PC2 allowance, mainly to ensure that costs which are not accurately represented elsewhere are captured correctly.

The only items that feeds through into PC3 relates to the notional rent on the Finglas building (€0.5m relating to the cost of the new Networks Services Centre relating to the Network Services Contract) which is owned by BGN but not included as an asset in the RAB.

#### **5.3.5 Pass through (allowed €99.6m; outturn €75.5m)**

These figures cover costs associated with:

- the regulatory levy paid by the distribution business to the CER;
- council rates;
- gas shrinkage; and,
- safety advertising & safety initiatives.

Gaslink costs are covered separately in Section 5.3.6 below.

The CER levy is viewed as a straight pass through items over which the distribution business had little control.

For rates, if the actual amount differed from the PC2 allowance, then the difference was shared on a 50:50 basis between the distribution business and customers.

The economic downturn and negotiations by the distribution business on the rateable valuation for the network has resulted in favourable rates variances.

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<sup>13</sup> The figures referred to here are those allocated to the distribution business only. The equivalent figures for transmission are an allowance of €70.6m and an actual of €76.5m. Other units to which this area provides services have been allocated a spend of €8.1m.

For gas shrinkage, the distribution business was incentivised to minimise the volume of shrinkage gas it used in comparison to the allowed volume, while the cost of shrinkage is a straight pass through. There have been favourable variances for shrinkage.

For safety advertising and initiatives, it was agreed that it was not possible to forecast these costs accurately. Instead these were revised annually in advance with 100% of the difference between the initial and revised forecast being passed through. When closing out safety costs for each year, the difference between actual costs and the revised forecasts were shared between the distribution business and customers on a 50:50 basis.

The figures have been reflected within the annual distribution tariff setting process, where relevant pass-through costs have been passed on to customers.

#### **5.3.6 Gaslink (allowed €3.2; outturn €3.0m)**

Gaslink Independent System Operator Limited, an independent subsidiary of Bord Gáis, commenced trading at the beginning of PC2 (early October 2007) and holds the Transmission and Distribution system operator licences for BGN. The primary function of Gaslink is to operate, maintain and develop the transmission and distribution systems safely, reliably and efficiently under economic conditions with due regard to the environment. As a separate legal entity Gaslink raises invoices for its charges to BGN.

For PC2, the CER recognised the need for greater clarity regarding the functions, responsibilities and operating costs of Gaslink and determined that the costs would be subject to annual review by CER. The determination also stated that 80% of the costs be charged to Transmission and 20% to Distribution. 80% of the costs or €12.2 million has been charged to Transmission Opex in PC2 and the remaining €3 million to Distribution.

The actual costs have been broadly in line with the allowances throughout PC2.

In July 2010 the Minister for Communications, Energy and Natural Resources decided that the Independent Transmission Operator model will be applied within BGÉ and it is envisaged that Gaslink will become integrated into the ITO at some stage during the 2012/13 period.

### **5.3.7 ITO operating costs in PC2**

In general the revenue to cover operational costs was set at the beginning of PC2 and, while the outturn is being reviewed here, no adjustments will be made for over or under spends by the distribution business. However, the PC2 decision stated that an exception to this approach would be where an event genuinely outside of the distribution business's control, which was not forecast at the time the control was set, leads to the distribution business incurring significantly more costs than expected, and which could severely impact on the distribution business's financial position.

BGN has claimed an additional allowance of €10m for the ITO Opex costs that arose in PC2 and were not anticipated at the time the PC2 allowances were set.

Following its review CEPA concluded that the additional ITO costs could have been contained. They recommended reducing costs to reflect the savings that were achievable in both the additional ITO operating costs and the wider network operating costs. Regarding the costs incurred in PC2, CEPA recommended an allowance of €4.8m (for distribution).

Having considered the issue further, the CER agrees that the ITO costs could have been contained by BGN and has decided to accept that the full allowance should not be given. This disallowance has been fed through to the revenue that the distribution business will be allowed to recover over the PC3 period and is illustrated in Table 4 below.

**Table 4: ITO operating costs incurred in PC2, (€m, 2010/11 prices)**

	€m
BGN's estimate of the additional ITO Opex costs in PC2	10.0
Less the unregulated portion	0.5
	9.5
Less further efficiency disallowance on costs	1.2
Total before allocation	8.3
Apportioned to Distribution	4.8
Apportioned to Transmission	3.5

### 5.3.8 Normalised costs

CEPA's review of historic operating costs fed through into their recommendations for the PC3 period. This is covered in more detail within the CEPA report published alongside the consultation paper and also within Section 6.2.

## 5.4 Conclusion

The above sections of this paper cover the distribution business's operating expenditure over the October 2007 to September 2012 period at a high level. More detail was also provided in the consultant's report on this expenditure which was published alongside the consultation paper.

When pass-through is excluded the distribution business overspent its allowance by €11.4m. This is offset by the distribution business's share of the saving against the pass-through cost allowance and there is no overall excess.

The CER has decided to allow €4.8m of additional costs relating to the ITO which were incurred in PC2 but for which no allowance had been made.

## **6.0 Forecast operational expenditure**

### **6.1 Introduction**

The section outlines the CER's final decisions regarding the distribution business's Opex over the October 2012 to September 2017 period. The recommendations provided by the CER's consultancy support (CEPA) were published alongside the consultation document.

In summary, CEPA completed a bottom-up assessment to develop a base year of normalised distribution Opex costs that represents the core historic 'business as usual' Opex. This was then revised to reflect additional items of Opex forecast to be incurred in future years. A further 1% year on year efficiency was also recommended by CEPA. CEPA's benchmarking of BGN, expected frontier shift and recent investments are discussed in this context.

The introduction of the ITO is discussed in Section 7.5. It is worth noting that operating costs in PC3 will be higher than would otherwise have been the case due to the introduction of the ITO, which was a Government decision made due to an EU requirement. While these extra costs are unavoidable, the CER has ensured that only efficient costs are allowed.

### **6.2 Development of allowances**

Section 5 provides detail on the distribution business's historical operating expenditure. CEPA's conclusion from its review of historic distribution operating expenditure was that the distribution business has not been able to fully justify the substantial increase in operating costs following the two major programmes it undertook in PC2 and that there is also an absence of evidence of net savings being delivered by these initiatives in PC3.

CEPA therefore did not accept the increased level of operating expenditure presented by the distribution business and instead based its projections on the level of normalised annual expenditure.

### **6.2.1 The normalised annual expenditure & adjustments**

CEPA completed a bottom-up assessment to develop a base year of normalised distribution Opex costs that represents the core historic 'business as usual' Opex and which was then revised to reflect additional items of Opex forecast to be incurred in future years.

CEPA's normalised costs were derived from a bottom-up analysis of actual Opex costs, adjusted for efficiencies and one-off costs, an understanding of material activities and their drivers, and made adjustments to reflect the evidence to support changes in costs going forward.

Further detail is provided within the CEPA document published alongside the consultation paper. In addition, following the consultation process and further discussions with BGN, there have been some amendments to the figures included in the consultation documents. Where changes have been made an explanation is provided in the relevant section below.

### **6.2.2 Efficiency improvements**

Following on from the work described in Section 6.2.1 above a further 1% efficiency improvement was applied to controllable costs, as described in Section 6.3.10 below. In addition to this a further adjustment of €1.0m over 5 years was then applied, as described in Section 6.3.9. The figures resulting from this process are outlined in Table 6 and Sections 6.3.2 to 6.3.8 below

## **6.3 Decision on allowances**

### **6.3.1 Introduction**

This section outlines the CER's final decision on allowances for the distribution business's operational costs over the PC3 period.

The allowances documented here (and covered in Table 6) include an adjustment of €1.0m and a 1.0% efficiency adjustment as listed in Section 6.2.2, which have been built into the final figures.

The network business underwent a transformation programme during the PC2 period, resulting in the distribution business's requests for PC3 being under different headings relative to PC2. The figures set out here are listed here are under the PC2 headings.

### **6.3.2 Direct operating expenditure (CER €164m)**

The distribution business reported its Distribution Direct Operating Expenditure (Opex) costs under the following key headings: (i) Network Maintenance; (ii) New Business; and (iii) Support Activities. These are discussed below in turn. Further information on these allowances can be found in the CEPA documents published alongside the consultation paper.

#### **Network Maintenance** (CER €102.8m)

This includes the direct Opex activities that are undertaken by the distribution business to maintain the distribution network assets in a safe and fit-for-purpose condition.

CEPA proposed an annual allowance of €18.7m which allowed for its 'normalised annual cost' from the historic Opex review and an additional allowance for certain additional costs arising in PC3. CEPA assumed that this level of annual cost remains constant throughout PC3<sup>14</sup>. The CER broadly agrees with the CEPA proposals, but following further discussions with BGN through the consultation process has decided to allow certain additional revenue which is deemed appropriate. This includes an additional €0.5m per annum for net cost leaks, due in part to the additional costs incurred as a result of the increase in the number of pre payment meters. Also an additional €0.25m per annum has been included under Response Activities to cover DRI maintenance.

Taking these changes and efficiencies into account the CER has decided to allow a total allowance of €102.8m over the five year period, which is an average of €20.6m per annum.

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<sup>14</sup> This excludes the 1.0% per annum efficiency improvement.

### **New business** (CER €7.4m)

This comprises Call Centre and Market Development. CEPA proposed an annual allowance of circa €1.3m which allowed for its 'normalised annual cost' from the historic Opex review. CEPA assumed that this level of annual cost remains constant throughout PC3. The CER agrees with CEPA's proposals with regards to the Call Centre costs and has included an allowance of €5.2m for the period.

Further to this, in the consultation paper the CER requested respondents' views on whether a larger allowance should be provided for market development. In the consultation responses received there were no strong views expressed by respondents.

Given the benefits that the promotion of new connections has with regards to the decrease in overall network tariffs and having considered the matter further, the CER feels that it is necessary for the long-term development of the network to provide a reasonable allowance. Therefore the CER has decided to allow an additional €0.2m per annum over the period resulting in a total allowance of €2.2m for the PC3 period.

### **Support Services** (CER €53.8m)

The key Opex activities within Support Activities are documented in Section 5.3.1 of this paper. CEPA proposed an annual cost of €10.9m which remains constant throughout PC3<sup>14</sup> and is broadly in line with its 'normalised annual cost' from the historic Opex review. The CER agrees with the figures proposed by CEPA and has decided to allow a total of €53.8m over the period, which equates to an average of €10.8m per annum once the 1% efficiency adjustment is taken into account.

### **6.3.3 Business support services (CER €115.8m)**

This area covers transportation, financial management and commercial functions. This includes key areas of financial control, code compliance, market arrangements, commercial and regulatory compliance, meter reading and customer support.

In previous years transportation and shared services were allocated to the distribution business. As a result of the organisational changes in PC2 and the establishment of the ITO these services have become an integral part of BGN, but still need to be apportioned over the transmission, distribution and unregulated business within BGN.

Following the CEPA review, the CER has decided that Business Support Services, as a shared cost, are to be allocated 55% to Distribution, 40% to Transmission and the remainder to unregulated business.

**Table 5: CEPA recommendations re business support**

	2012/13 €m	2013/14 €m	2014/15 €m	2015/16 €m	2016/17 €m	Total €m
Distribution	23.4	23.5	24.0	24.1	24.2	119.3
Transmission	16.9	17.0	17.4	17.5	17.5	86.3
Other	2.2	2.2	2.2	2.2	2.3	11.1
Total	42.4	42.7	43.6	43.8	44.0	216.7

The above table summarises CEPA's recommendations<sup>14</sup>. The CER broadly agrees with the CEPA recommendations and with the split between Distribution and Transmission. After efficiencies have been applied the CER has decided upon a final allowance of €115.8m for Distribution Business Support Services.

### **6.3.4 Innovation (CER €0.8m)**

#### Allowances

As part of this process, BGN proposed a number of innovation projects that collectively amount to c. € 12.5m of transmission Opex and Capex-related costs and c. €13.5m of distribution Opex and Capex-related costs.

Further detail on projects proposed by BGN (which cover areas such as compressed natural gas in transport, bio-methane injection into the gas grid, etc) can be found in the CEPA documents published alongside the consultation

paper.

CEPA proposed an innovation allowance of €8m (for transmission and distribution). In order to avoid complications of including small capital projects in the RAB, and to be consistent with its views on the focus of innovation funding CEPA recommend that the €8m be funded purely as Opex.

CEPA then reviewed a BGN proposal that the €8m be allocated €0.8m to distribution and €7.2m to transmission and agreed that it was appropriate. The CER has decided to accept CEPA's recommendation and allow a total of €0.8m for distribution Opex under this heading.

#### Governance arrangements

As part of its proposals regarding innovation BGN discussed the idea of forming an innovation group (to manage resources, project selection, etc) which would work with internal and external BGN stakeholders, especially the CER to share knowledge and better utilise available resources.

The CEPA paper published alongside the consultation document discussed BGN's proposal and similar arrangements that are in place elsewhere. CEPA proposed the following should CER decide to go ahead with an innovation funding mechanism for PC3:

- the concept of an innovation fund should be consulted on with the gas industry before the structure of the fund is confirmed;
- BGN should only be able to access funding where it has proposed specific projects that are agreed and signed off by an industry innovation group or the CER (or both);
- capped allowances should be set for individually approved projects to incentivise BGN to find efficiency savings;
- BGN would be expected to develop projects that involve wider stakeholders who would receive part of the innovation funding provided through the network tariff;
- BGN should be expected to make a minimum financial contribution to an innovation project from its own resources; and

- appropriate monitoring and evaluation processes should be developed and approved by the CER.

In the consultation document the CER asked respondents to put forward their views regarding appropriate governance arrangements. The CER specifically asked respondents to comment on whether funding (including perhaps full funding for a project which BGN would not have direct involvement in) should be made available to stakeholders other than BGN? In addition respondents were asked to put forward comments on what stakeholders should make up the group which would be responsible for selection of projects, etc and what body should have final responsibility for selection of projects.

There were limited comments from respondents on this issue, but it was stated that funding should only be sanctioned for projects of common interest to the Irish gas industry. It was also suggested that an industry body should be formed, consisting of the CER, BGN, the Irish Offshore Operators' Association and gas shippers.

The CER has decided that further consideration should be given to this matter and agrees with CEPA to the extent that there should be engagement with the gas industry. Therefore, while provision has been made to allow a total of €8m to be collected for innovation, the CER will consider further the governance arrangements for this fund and will engage with stakeholders as appropriate.

In order to administer any projects under this area the CER has decided to allow BGN to retain €0.1m per annum from the total allowance for innovation. It is important to highlight that this decision does not increase the overall allowed revenue figure, but instead allocates a small part of the innovation total specifically to BGN in order to cover the costs involved in administering the fund. In line with the decision on the splitting of the total €8m allowance, 10% of the €0.1m should come from the €0.8m allowed for Distribution Opex, with the remaining 90% coming from Transmission Opex.

### **6.3.5 Miscellaneous charges (CER €2.5m)**

During PC2 a large number of items were charged under this heading. The only item that appears for PC3 is Finglas rent of €0.5m relating to the cost of the new Network Services Centre. The bulk of the annual cost relates to the notional rent on the Finglas building which is owned by BGN but is not included as an asset in the RAB.

CEPA recommended an allowance of €2.5m over five years for this cost and the CER has decided to accept this recommendation.

### **6.3.6 Glide Path to Efficiency (CER €8.0m)**

This final decision paper would have set a total distribution Opex of €392m for the five year period covered by PC3, which represented a significant reduction of €71m (15%) below the €463m originally requested by the distribution business. The CER believes that while BGN should only be allowed a level of Opex that covers efficient costs, it is also recognised that BGN will be challenged to immediately reduce their Opex to the levels proposed in the consultation document. It is also of the utmost importance that BGN continue to maintain the highest of safety standards in their operation of the gas distribution network.

While the CER expects that BGN will be able to introduce measures to reduce costs and improve efficiency, this may take some time. Therefore the CER has allowed an additional €5m in year 1 and €3m in year 2 of the price control in order to provide BGN with a glide path to efficiency. These additional revenues will ensure that BGN continue to maintain and operate the network to the highest safety standards while allowing them time to make the necessary adjustments to improve efficiency.

### **6.3.7 Pass through costs (CER €99.3m)**

A number of costs are deemed to be either fully or partially outside of the distribution businesses control. Changes to these costs are, subject to review, passed through to the final customer as part of the yearly tariff updates.

Changes to the CER levy are deemed to be largely outside of the distribution

business control and 100% of this cost is passed through to customers.

Other pass through items are subject to an incentive sharing mechanism as detailed below.

#### CER levy (CER €6.6m)

An allowance of €1.3m per annum has been included for this item. All of the variances between this allowance and the actual cost will be passed through to consumers via distribution tariffs.

#### Shrinkage (CER €19.2m)

Shrinkage gas or unaccounted for gas (UAG) represents the unaccounted or unallocated distribution gas. The distribution business had agreed UAG factors of 1.4% for 2007/8 falling to 1% in 2011/12. The actual UAG has been markedly lower at 0.85% for 2007/8 falling to 0.42% in 2010/11, the latest available year.

The distribution business is forecasting an increase to 1.3% within the first year of PC3 attributing the increase to new industry processes based on 'revenue protection'. The CER recognises that UAG is likely to increase, however it believes that BGN should be incentivised to keep levels as low as possible. Therefore the CER decision is to set a shrinkage allowance based of 1% in the first year of the price control, reducing to 0.75% over the course of PC3.

#### Revenue Protection (CER €2.75m)

In the consultation document the CER set out that it was considering allowing a further allowance (of approximately 0.25%) in order to cover costs associated with a revenue protection function. The CER has decided to allow €2.75m for revenue protection over the course of PC3, which is an average of approximately 0.15% per annum.

#### Rates (CER €62.4m)

CEPA proposed to accept the PC3 forecast of €62.4m over PC3 compared with €36.7m actual for PC2. CEPA noted that BGN stated that it has agreed the rateable valuation to be applied from 2011 to 2015. This resulted in an increase

of €3m per annum for onshore regulated assets across transmission and distribution. Also, the apportionment between the transmission and distribution business was changed in 2010/11 to reflect the rateable valuation. This resulted in a significant shift from 55:45 (TBU:DBU) to 39:61 (TBU:DBU).

Following discussions with CEPA on the matter the CER has decided that €62.4m is allowed to be recovered through distribution tariffs.

As during PC2, this allowance will again be subject to a mechanism where 50% of the difference between approved and actual levels will be passed through to consumers, with the remainder being borne (or received) by the distribution business.

#### Safety (CER €4.7m)

During PC2 there was uncertainty over safety related costs (such as safety advertising and initiatives) and so it was considered necessary to treat this expenditure as a pass-through item.

During PC2, safety initiatives were driven by Safety Policy, the Gas Safety Committee and incidents/ matters arising that required specific action from a safety perspective.

In CEPA's view, aspects of the safety initiatives and advertising related expenditure should remain a priority for the distribution business, and given the uncertainty of the costs should remain a pass through item.

The PC2 revenue control included an allowance to cover a range of schemes to then be agreed over the control period.

Following direction from the CER, CEPA approached setting the allowances for safety initiatives and advertising in PC3 differently to PC2. They proposed that €0.6m per annum should be allowed initially for safety advertising and €0.09m per annum for safety initiatives.

Should further revenue be required, then a submission would be made to CER (year in advance) documenting why the project is required and detailing what additional costs would be caused. Following a review of the submission, the CER will make a decision on whether the costs are to be passed through to consumers. It is intended that this process will be used each year (when necessary) to set a budget for the forthcoming year. Once that budget is set a 50:50 sharing arrangement (as currently in place for PC2) will then apply to allowances creating an incentive for the distribution business to control costs against an established target.

The CER has set a €0.6m allowance for safety advertising (per annum) and a further allowance of €1.3m in the first year of the price control. In addition there was a €0.09m allowance for safety initiatives (per annum). The CER is also to adopt the above approach whereby additional requests could be made on a yearly basis, leading to a different budget against which a 50:50 sharing mechanism would apply.

#### **6.3.8 Gaslink (CER €2.9m)**

During PC3, Gaslink will be re-amalgamated into the network business. CEPA recommended a total allowance of €11.9m for the 'Gaslink' activities that are to be completed by the network business when Gaslink is re-amalgamated. They recommended allocating the allowance 20% (€477k pa, €2,387 for PC3) to distribution and 80% (€1,910k pa, €9,549k for PC3) to transmission.

In addition to the CEPA recommendation, the CER has allocated an additional €0.55m per annum for market arrangements, of which 20% will be allocated to distribution and 80% to transmission - in line with the above allocation. Taking this into consideration the CER has set the distribution allowance for Gaslink in 2012/13 at €0.6m. A total of €2.9m is to be allowed for the PC3 period.

Gaslink will continue to operate independently for some if not all of 12/13. The €0.6m allocation, set out above is for the twelve months of 2012/13. If Gaslink is re-amalgamated at an earlier stage, then CER would take back the difference between the €0.477m recommended by CEPA and the €0.6m on a pro rata

basis.

### **6.3.9 Further adjustments (CER -€1.0m)**

Overall the introduction of the ITO has increased Opex costs in BGN over PC3. The CER's advisers have reviewed these costs and determined an appropriate level of ongoing costs.

CER notes that the choice of ITO was made in the light of the expected ongoing operating costs being lower under the ITO structure than under the alternative ISO structure. The CER takes the view therefore that it is appropriate to reduce this increased cost by €2m over the period (€1m in distribution). This is over and above any other efficiencies expected in the period.

### **6.3.10 Further adjustments**

The work described in Section 6.2.1 above led to the figures outlined in Sections 6.3.2 to 6.3.8.

The table also includes a further adjustment of €1.0m, as described in Section 6.3.9, applied over the 5 years. In addition a 1% per annum efficiency improvement has been applied to controllable costs. The figures resulting from that are outlined in Table 6 below.

CEPA outlined a number of factors which fed into this 1% efficiency improvement. The likelihood of future frontier shift based on other regulators' recent price control decisions was considered. CEPA also completed a benchmarking analysis using different techniques. They note that there are limitations with benchmarking BGN (a relative outlier) to the GB GDNs, but consider that their findings supported both the 'bottom-up' proposals and the view that BGN has the potential to deliver further ongoing efficiency savings in PC3. CEPA also noted the recent investment that BGN has made in its business systems and process in recent years as an argument for a year on year efficiency improvement.

These are outlined in more detail within the CEPA document which was published alongside the consultation paper.

In the consultation document the CER asked respondents to provide their views on whether a 1% per annum efficiency improvement was appropriate. A number of respondents stated that they supported the inclusion a 1% efficiency target applied to Opex as an incentive for BGN to introduce efficiencies.

## 6.4 Conclusion

The above sections of this paper cover the final decision on the allowances for the distribution business's Opex over the October 2012 to September 2017 period.

The CER has decided to allow the distribution business to collect €392m through distribution tariffs to cover its operating costs over the October 2012 to September 2017 period. This is €71m (15%) lower than the €463m originally requested by the distribution business for this period, and €33m (8%) lower than the €425m that was subsequently requested.

Table 6 below, incorporating a 1% per annum efficiencies on controllable costs, shows an additional allowance for the independent existence of Gaslink for the first year of the control and an additional efficiency of €0.2m per annum, applied after the 1% efficiency adjustment.

As detailed in CEPA's reports, the table provides the figures in the PC2 expenditure categories.

**Table 6: Opex including efficiency & other adjustments (€m, 10/11 prices)**

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
2010/11 Monies €k	€000s	€000s	€000s	€000s	€000s	€000s
<b>Direct</b>						
Installation Activities	2,228	2,205	2,183	2,161	2,140	10,917
Leak Survey	529	521	514	508	502	2,574
Net Cost Leaks	3,965	3,930	3,896	3,862	3,828	19,481
Response Activities	10,150	10,051	9,953	9,856	9,760	49,770
System Operations	2,376	2,352	2,329	2,305	2,282	11,644
UGGS	59	59	58	58	57	291

Smart Metering	4070	4070				8,140
<b>Network Maintenance</b>	<b>23,377</b>	<b>23,188</b>	<b>18,933</b>	<b>18,750</b>	<b>18,569</b>	<b>102,817</b>
Call Centre	1,063	1,052	1,042	1,031	1,021	5,209
Market Development	448	445	443	440	438	2,214
<b>New Business</b>	<b>1,511</b>	<b>1,497</b>	<b>1,485</b>	<b>1,471</b>	<b>1,459</b>	<b>7,423</b>
Add Mayo/Galway Opex	501	496	491	486	481	2,456
Business Regulation and Planning	172	157	155	154	152	790
General Management	2005	1985	1966	1946	1926	9,829
Meter Control and Instrumentation	682	675	668	661	655	3,341
Odourisation	70	70	69	68	68	344
Radio Room	1920	1901	1882	1864	1844	9,411
Safety & Quality	2507	2481	2457	2432	2408	12,285
Sales & Service Support	2908	2878	2850	2822	2793	14,252
Stores	213	211	209	207	205	1,043
<b>Support Activities</b>	<b>10,978</b>	<b>10,855</b>	<b>10,747</b>	<b>10,639</b>	<b>10,532</b>	<b>53,751</b>
<b>Sub-total Direct</b>	<b>35,866</b>	<b>35,540</b>	<b>31,165</b>	<b>30,860</b>	<b>30,560</b>	<b>163,991</b>
<b>Business Support Services</b>	<b>23,131</b>	<b>23,062</b>	<b>23,313</b>	<b>23,187</b>	<b>23,060</b>	<b>115,753</b>
Innovation fund	160	160	160	160	160	800
Miscellaneous Deductions/Charges	503	503	503	503	503	2,515
Glide Path to Efficiency	5,000	3,000	-	-	-	8,000
<b>Overall Total Direct</b>	<b>64,660</b>	<b>62,265</b>	<b>55,141</b>	<b>54,710</b>	<b>54,283</b>	<b>291,059</b>
CER LEVY	1,320	1,320	1,320	1,320	1,320	6,600
Rates( Pass Through)	11,285	11,289	11,883	13,408	14,512	62,377
Safety Advertising	1892	600	600	600	600	4,292
Safety Initiatives	90	90	90	90	90	450
<b>Subtotal</b>	<b>14,587</b>	<b>13,299</b>	<b>13,893</b>	<b>15,418</b>	<b>16,522</b>	<b>73,719</b>
Gas Shrinkage	4,318	4,106	3,845	3,586	3,327	19,182
Shrinkage Gas Capacity Charge	717	722	726	732	738	3,635
Revenue Protection	551	551	551	551	551	2,755
<b>Gas Shrinkage</b>	<b>5,586</b>	<b>5,379</b>	<b>5,122</b>	<b>4,869</b>	<b>4,616</b>	<b>25,572</b>
<b>Pass through</b>	<b>20,173</b>	<b>18,678</b>	<b>19,015</b>	<b>20,287</b>	<b>21,138</b>	<b>99,291</b>
Gaslink ISO	602	578	573	569	564	2,886
Additional efficiency	-200	-200	-200	-200	-200	-1,000
<b>Grand Total</b>	<b>85,235</b>	<b>81,320</b>	<b>74,529</b>	<b>75,365</b>	<b>75,785</b>	<b>392,236</b>

## 7.0 Historical capital expenditure

This section examines the historical capital expenditure undertaken by the networks business. The outturn expenditure is assessed, looking at the output in terms of delivery and efficiency.

### 7.1 Introduction

The networks business undertook a significant programme of investment during PR2. The CER allowed, in the PC2 determination, over €600m (inflated) of Capex related to network and non-network investments. Notwithstanding the impact of the recession there was significant expenditure on new connections, reinforcement, network renewal and IT over the period, with the distribution business reporting an expenditure of €435m.

Table 7 below summarises the original (inflated) allowances for the key categories of distribution Capex, the flexed distribution allowance, the total distribution variance, the scope variance and the efficiency variance, for each tariff year in PC2 plus the final year of PC1 – 2006/7 – i.e. six tariff years in total. It demonstrates the extent to which BGN has under spent its Capex allowances in PC2 and the final year of PC1.

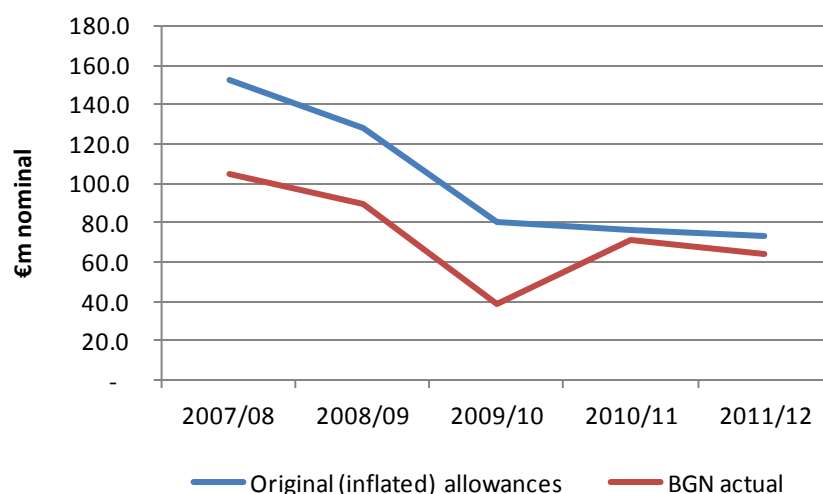
**Table 7: Distribution related Capex (PC2 and 2006/07)**

Work Category	Original (inflated) allowance	Flexed (inflated) allowance	Total actual spend	Total variance in spend	Flexed (scope) variance	Total efficiency variance
Net growth Capex <sup>1</sup>	352,842	204,967	191,395	161,446	147,875	13,572
Replacement Capex	226,799	240,674	199,488	27,311	(13,875)	41,186
Non-pipe	44,087	n/a	44,727	(639)	-	-
<b>Total</b>	<b>623,728</b>	<b>n/a</b>	<b>435,609</b>	<b>188,118</b>	<b>134,000</b>	<b>54,758</b>

*Note 1: Including customer contributions*

The key variances that the distribution business highlights across the PC2 period include:

- lower number of connections due to the change in economic environment;
- expanded new towns programme;
- accelerated meter replacement programme.



**Figure 1: Actual outturn and projected outturn distribution Capex in PC2 vs. original PC2 (inflated) allowances**

Table below outlines the Capex submission by the distribution business and the efficiency adjustments made by CER to this submission.

**Table 8: Capex submission and adjustments**

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	Total
<b>BGN position</b>	<b>61.85</b>	<b>95.27</b>	<b>107.32</b>	<b>38.67</b>	<b>70.98</b>	<b>64.09</b>	<b>438.18</b>
Residential services <sup>1</sup>	-0.7	-1.4	-0.8	-1.1	-0.9	-0.2	-5.1
Facilities <sup>2</sup>	-	-	-	-0.2	-0.2	-0.2	-0.6
Total adjustments	-0.7	-1.4	-0.8	-1.3	-1.1	-0.4	-5.7
<b>Consortium position</b>	<b>61.15</b>	<b>93.87</b>	<b>106.52</b>	<b>37.37</b>	<b>69.88</b>	<b>63.69</b>	<b>432.48</b>

Note 1: Adjustment allocated on a percentage basis to years where there was a negative efficiency variance

Note 2: Adjustment spread equally across last three years of PC2

From a purely technical perspective, CER's advisers regarded the majority of actual incurred distribution Capex as justified, necessary and efficient. However, the PC2 guidance was clear that where an *overspend* arises because a project has been completed at higher cost than anticipated, CER would consider whether all the actual Capex incurred should be included in the starting RAB for PC3. Inclusion of actual incurred Capex in the RAB was not automatic. The regulatory guidance for PC2 was clear that CER would take a category by category approach to assessing both under and overspends in distribution. Finally the guidance was also clear that the burden of proof lay with the

distribution business to demonstrate that higher actual Capex was efficiently incurred, e.g. arising from a competitive tender or a reflection of construction price inflation in Ireland.

Overspend was reported by the distribution business under the heading of Facilities. The distribution business noted that the formation of the ISO, (Gaslink) and Second Directive compliance, meant that facilities at a number of sites had to be reconfigured / refurbished to accommodate staff movements and new security arrangements had to be put in place to ensure compliance conditions were met.”

CER’s advisers noted that while the distribution business claimed “steps were taken where possible to address costs with [regard to] facilities reconfiguration to accommodate ISO operational needs while remaining compliant” the distribution business’s submissions provided no evidence of what actions were taken or how this impacted on costs.

The advisers also noted that the establishment and on-going costs of Gaslink were originally provided for in the 2007/08 – 2011/12 Revenue Decision Papers and therefore the distribution business has received - or at least had the opportunity to request - additional ISO facilities Capex at the time of the PC2 distribution control revenue review.

Given the above, and the Capex overspend being partly driven by additional regulatory and legislative requirements, the advisers proposed only 50% of the facilities Capex over spend be allowed by the CER.

Overspend was reported by the distribution business under the heading Residential Services. Noting that the requirements of local authorities for utilities carrying out street works are becoming more demanding, and inherently more costly, in Ireland as is the case in the UK and therefore that this cost driver is non-controllable by the distribution business, the CER’s advisers took the view that poor unit cost performance accounts for part of the overspend in this category. The distribution business highlights that there was a change in contractors, a change in contractor pricing mix and a change in economic circumstances over the price control period that has caused the overspend.

In contrast to local authority requirements these factors are, in the advisers’ view, partly controllable by the distribution business and therefore the advisers

proposed that €2.8m of the overspend be disallowed while the remaining €4.6m should be subject to a 50% allowance.

Therefore the advisers recommended that overall, €5.1m of the total overspend should be disallowed for residential services. The CER has decided to accept the advisers recommendations and disallow €5.1m

## **7.2 Objective of the Historical Capex Review**

The main objectives in the review of the networks business's historical Capex are to assess whether the expenditure has been incurred efficiently and the expected benefits for customers have been achieved. The following areas were examined in detail:

- Comparing the outturn expenditure with the allowed expenditure. The tariff allowance (inflated to nominal prices) was compared to the actual spend to determine the distribution variance. A flexed tariff allowance is then established by calculating the actual quantities at the tariff allowance unit cost for the gas year. If there is no tariff unit cost (because there are no tariff quantities) then the flex amount equals the actual amount.
- Understanding the differences between the allowed expenditure and the outturn expenditure; and
- Assessing cost drivers and their impact on performance of the Capex programme and considering any requests for efficiently incurred cost increases.

## **7.3 Growth Related**

Key aspects of new business, or new connections, are identified below:

- Domestic connections for housing schemes – There was an allowance for 121,485 such connections from 06/07 to 11/12, there were a total of 43,610 such connections made in the period.
- Domestic connections for non housing schemes – generally one off or existing housing: There was an allowance for 33,001 such connections from 06/07 to 11/12, there were a total of 25,090 such connections made in the period.
- Industrial and Commercial connections– these connections can vary from

small commercial premises to a large factory: There was an allowance for 7,369 such connections from 06/07 to 11/12, there were a total of 6,903 such connections made in the period.

- Industrial and Commercial Mains– this refers to the length of mains installed to service the premises above: There was an allowance for 272km of such mains from 06/07 to 11/12, there was a total of 161km of such mains laid in the period.
- New Towns– There was an allowance for 229km of new towns mains from 06/07 to 11/12, there was a total of 369km of such mains laid in the period. In addition to the towns identified in the Phase I, II and III reports, the town of Macroom was included on a stand alone basis.

## **7.4 Network Reinforcements**

The distribution business's Replacement Capital Expenditure programme during PC2 has been largely associated with the Accelerated Mains Renewal Programme, which involves the replacement of cast iron and other metallic distribution mains and service pipes with modern, polyethylene (PE) pipe material and the Meter Replacement Programme.

Key aspects of replacement, or reinforcement works, are identified below:

- Planned and unplanned mains renewal – There was an allowance for 716km of such mains renewal from 06/07 to 11/12, there were a total of 754km of such renewals made in the period.
- Planned and unplanned service renewal – There was an allowance for 32,791 such service renewals from 06/07 to 11/12, there were a total of 26,587 such service renewals made in the period.
- Reinforcement mains– There was an allowance for 237km of such mains reinforcement from 06/07 to 11/12, there were a total of 192km of such reinforcement made in the period.
- Domestic meter replacement– There was an allowance for 16,907 such meters to be replaced 06/07 to 11/12, there were a total of 74,105 such meters replaced in the period. This was further to the approval by the CER of the meter replacement programme.
- Pre Payment Meters – There was an allowance for 13,446 such meters to

be installed 06/07 to 11/12, there were a total of 42,958 such meters replaced in the period. This increase in installation rate was largely driven by the deterioration in the economy post 2008.

## **7.5 Network Non-Load related**

The distribution business reported an overspend<sup>15</sup> in this category versus the allowance. It highlighted that the primary cost drivers for facilities Capex during the period were regulatory and legislative driven:

*“Early on in the PC2 period to facilitate the establishment of RGII, the safety function had to be reorganised and Century Business Park was vacated and facilities at Donmay House had to be reorganized and refurbished to accommodate the staff that need to be re-accommodated.*

*In addition, the formation of the ISO, (Gaslink) and Second Directive compliance, meant that facilities at a number of sites had to be reconfigured / refurbished to accommodated staff movements and new security arrangements had to be put in place to ensure compliance conditions were met.”*

The CER has decided to accept the advisers’ recommendation to disallow 50% of the requested Capex overspend in this category.

## **Independent Transmission Operator**

EU Directive 2009/73/EC, as part of the Third Energy Package, came into force in September 2009 and contains unbundling provisions designed to separate the supply and networks activities of Vertically Integrated Utilities, such as BGÉ, in order to facilitate non-discriminatory access to gas transmission networks. BGÉ is a Vertically Integrated Utility (VIU) in both Ireland and Northern Ireland. The Directive outlines a number of models by which Member States can achieve compliance with the unbundling requirements. The Minister for Communications, Energy and National Resources has chosen to implement the Independent Transmission Operator (ITO) model in respect of BGE and the necessary regulations were brought into force in late 2011 (SI 630 of 2011). Under the ITO model, a legally separate and ring-fenced independent subsidiary of BGE will

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<sup>15</sup> See Table for details.

own and operate gas transmission systems in Ireland, Northern Ireland and in onshore Scotland. This change will involve an amalgamation of Gaslink, BGN, BGÉ UK and BGÉ NI functions. In order to ensure compliance, BGÉ are obliged to carry out this re-structuring during 2011-12.

CER/11/170 stated *“The CER has now decided that efficiently incurred EU Third Package implementation costs attributable to BGÉ as the Vertically Integrated Utility in Ireland will be recovered from end users in Ireland via network charges. It is anticipated that the recovery of these efficiently incurred costs will take place over a number of years commencing in 2012/13.”*

Pursuant to the above BGE proceeded with the creation of an Independent Transmission Operator (ITO) in line with EU Third Energy Package requirements during PC2. This work within BGN was known as Project 3.

In the PC3 process BGN submitted costs of €34.5m for ITO setup costs. Having reviewed the BGN submissions on this matter CER’s consultants took the view that €24.0m was an appropriate allowance for this project.

Regarding ITO setup costs it was noted in CER/10/149 that *“BGE put forward a high level estimate of €22m to re-structure Gaslink and BGN so as to carry out the functions of an Independent Transmission Operator (ITO). Following Ministerial approval of the ITO model under the Third Package, BGN have commenced the planning and implementation associated with the ITO model. However, it is recognised that uncertainty remains regarding the final cost.”*

Thus the high level estimate of ITO setup costs around the time that the ITO model was approved was €22m.

In recommending €24.0m as an appropriate allowance for this project CER’s consultants, as a cross check, included a “generous” allowance of €160k per person affected by the project and included a further 25% to cover off the legal complexities involved in a legislation driven company re-organisation, totalling €200k per person.

Taking the original budget into account and allowing for a 12.5% adder to the €160k per person allowance CER remains of the view that a total allowance of €22.5m is appropriate for this project.

In line with CER/11/170, the CER has decided to treat a proportion of the €22.5m of ITO setup costs as a capitalised expenditure with a depreciation life of 15 years and to recover these costs from Network users through tariffs in Ireland. In line with the approximate ratio of customer numbers between the markets in Northern Ireland and Ireland the CER considers that six sevenths is a reasonable pro rata for the ITO setup costs “*attributable to BGE as the Vertically Integrated Utility in Ireland*” and has made the decision to allow that amount (that is, six sevenths of €22.5m) for recovery through network tariffs.

In the 2010/11 tariffs €11m was recovered through transmission and distribution tariffs as a provisional sum towards ITO setup costs. The €11m was split 80% to transmission and 20% to distribution. In line with the decision to capitalise the full amount of the appropriate ITO set up costs, €11m will be deducted from the allowed revenues over PC3 in order to avoid customers paying twice for this work.

In summary, the CER’s final decision is that six sevenths of the €22.5m of approved ITO setup costs will be split between the transmission and distribution RABs and an allowance of minus €11m will be made to PC3 allowed revenues to avoid double payment for this work.

## **7.6 Variations between allowed and actual PR2 Capex**

### **7.6.1 Benefit Retention**

The PR2 determination provided for a five-year rolling retention of efficiency savings for Capex. This concept is detailed in the CEPA paper CER/12/057(d) published alongside the consultation document. Where the networks business can show that avoided Capex is due to efficiencies on its part (where it changes the scope to generate a cost saving or it achieves lower prices for the same scope) it is allowed to retain the revenue (depreciation and return) associated with the unspent Capex for a period of five years. The determination specified that reduction in volumes of investment would not be accepted as efficiency.

The total value of such “efficiency savings” in PC2 was €60.3m earning BGN

€23.6m over the period.

Where there is a negative scope change (the scope changes with an increase in costs) or where there is an overspend (called negative efficiency) AND these changes are deemed efficient the “excess cost” is allowed onto the RAB but the distribution business does not receive a return on the “excess” investment for the period of PC2. Depreciation on the “excess” investment is allowed in PC2 and the asset is treated in the same way as any other asset in PC3 and onwards. Examples of this concept include where prices rise unavoidably over the period or a solution more expensive than the original solution is required. This concept is detailed in the CEPA paper CER/12/057(d).

The total value of such “negative scope” or “negative efficiency” in PC2 was €47.8m which resulted in BGN forgoing a return of €6.5m over the period.

## 7.6.2 Opening RAB for 2011<sup>16</sup>

### PC1 close out RAB

Table shows the distribution business’s RAB for the close out of PC1 as specified in the CER’s determination for PR2 (CER/07/111). Table shows this in 10/11 monies. Both include a forecast of Capex for the 06/07 gas year.

**Table 9: PC1 RAB as specified in Table 7.3 of CER/07/111**

<b>Figures as per PC2 decision (05/06 terms)</b>	
Opening RAB for Oct 06	1,061.7
Closing RAB for Sept 07	1,133.7
Capex for 06/07 gas year	113.5

**Table 10: PC1 RAB as specified in Table 7.3 of CER/07/111 in 10/11 monies**

<b>Figures as per PC2 decision (inflated to 10/11 terms)</b>	
Opening RAB for Oct 06	1,111.2
Closing RAB for Sept 07	1,186.5

<sup>16</sup> Table to Table 13 are from the excel model which has been published alongside this paper.

Capex for 06/07 gas year	118.8

Table below outlines the approved close out RAB for PC1. The change in the opening RAB between Table 11 and Table is due to minor adjustments such as an error in connection with the write off of Dublin cast iron pipe and the identification of more accurate inclusion dates. The below table includes outturn 06/07 Capex, whereas the above tables include a forecast.

**Table 11: PC1 Closeout RAB as approved**

<u>Approved outturn figures, 10/11 terms</u>	
Opening RAB for Oct 06	1,100.0
Closing RAB for Sept 07	1,122.6
Capex for 06/07 gas year	62.2

## PC2 RAB

Table 12 shows the networks business's RAB as specified in the CER's determination for PR2 (CER/07/111). Table 13 shows this in 10/11 monies.

**Table 12: PC2 RAB as specified in Table 7.3 of CER/07/111**

<u>Figures as per PC2 decision (in 05/06 monies)</u>					
	2007/8	2008/9	2009/10	2010/11	2011/12
Opening RAB	1,133.7	1,234.9	1,315.6	1,350.5	1,377.9
Closing RAB	1,234.9	1,315.6	1,350.5	1,377.9	1,399.6
Capex	143.1	121.1	77.9	73.2	69.8

**Table 13: PC2 RAB as specified in Table 7.3 of CER/07/111 in 10/11 monies**

<u>Figures as per PC2 decision (in 10/11 monies)</u>					
	2007/8	2008/9	2009/10	2010/11	2011/12
Opening RAB	1,186.5	1,292.4	1,376.9	1,413.4	1,442.1

Closing RAB	1,292.4	1,376.9	1,413.4	1,442.1	1,464.8
Capex	149.8	126.8	81.5	76.6	73.1

Table 14 shows the approved out turn RAB for each year. Note the change in 2007/08 opening RAB from Table 13 to Table 14 is due to the adjustments made in Table above.

**Table 14: PC2 RAB as approved**

<b>Figures as allowed (in 10/11 monies)</b>					
	2007/8	2008/9	2009/10	2010/11	2011/12
Opening RAB	1,122.6	1,177.7	1,241.0	1,240.3	1,269.3
Closing RAB	1,177.7	1,241.0	1,240.3	1,269.3	1,288.5
Capex	92.1	105.0	37.8	73.7	63.3

The opening regulatory asset base value for 2011/12 is set at €1,269.3m. This is an important value as it is calculated using outturn Capex figures, while the closing value for 2011/12 is calculated using estimates for 2011/12 Capex.

### 7.6.3 Adjustments to clawbacks

The final distribution model published alongside this decision paper shows how the clawbacks (relating to return and depreciation on unspent Capex) are adjusted prior to being returned to the network customer.

The approach for the treatment of clawbacks, is as per that set out in the consultation, whereby revenue that was earned on unspent Capex is adjusted, to allow for the fact that the network company has held the revenue for a number of years prior to returning it to the networks customer.

## 8.0 Forecast capital expenditure

### 8.1 Introduction

The distribution business submitted a Capex programme for PC3 of €452m net of customer contributions. The breakdown of the Capex submitted is given in Table 15 below.

**Table 15: BGN Capex submission for PC3**

Category	12/13	13/14	14/15	15/16	16/17	Total
Growth						
Distribution mains	7,629	8,254	9,943	10,444	10,444	46,714
Distribution services	11,838	12,178	13,165	13,459	13,459	64,099
Distribution meters	3,778	3,978	4,753	5,035	5,035	22,580
Customer contributions	(2,841)	(2,986)	(3,128)	(3,164)	(3,164)	(15,282)
New towns / Infills	12,662	8,876	-	-	-	21,538
Innovation	1,000	1,250	1,913	1,275	775	6,213
<b>Total Growth</b>	<b>34,567</b>	<b>34,550</b>	<b>30,645</b>	<b>32,050</b>	<b>31,550</b>	<b>163,362</b>
Replacement						
Distribution meters	22,756	29,931	53,993	51,974	31,612	190,267
Mains reinforcement	5,588	3,035	3,623	5,294	5,294	22,833
Mains replacement	813	813	0	0	0	1,625
Operational upgrades	3,427	4,815	9,325	7,377	7,377	32,321
Service replacement	4,901	4,905	3,678	1,812	1,817	17,113
<b>Total replacement</b>	<b>37,485</b>	<b>43,498</b>	<b>70,619</b>	<b>66,457</b>	<b>46,099</b>	<b>264,158</b>
Non-pipe						
IT	5,453	4,482	4,096	3,022	2,930	19,982
Facilities	1,576	1,098	891	633	587	4,784
<b>Total non-pipe</b>	<b>7,029</b>	<b>5,580</b>	<b>4,986</b>	<b>3,654</b>	<b>3,516</b>	<b>24,766</b>
<b>Total PC3 Capex</b>	<b>79,081</b>	<b>83,629</b>	<b>106,250</b>	<b>102,161</b>	<b>81,166</b>	<b>452,287</b>

The networks business submission contained a significant programme of capital expenditure for the PC3 period. BGN also submitted for an allowance for smart metering, this is dealt with in Section 8.4.4. The following sections review and assess the requested Capex and detail the CER's final decisions on allowed Capex.

### 8.2 Objectives

The objective of the review of the PR3 Capex programme submitted by the networks business was to ensure that the Capex is necessary and represents

value for money for the consumer. In order to achieve this objective the CER, assisted by our advisors, reviewed:

- The policies and standards adopted by the networks business that underpin the Capex programme;
- The procurement strategies used to procure plant and contractors;
- The strategies adopted by the networks business to ensure that planning expenditure is needed, represents best value for the customer and can be delivered in the timeframe; and,
- The benefits that Capex will bring to the system and whether these benefits are valued by the customer.

### 8.3 Overview

A key outcome of BGN's Network Transformation Project (NTP) is the development of the High Performance Utility Model (HPUM), which includes a dedicated Asset Management function. This effectively means that the 'traditional' asset classes associated with transmission and distribution activities are now reclassified under the five Asset Classes of:

- 1) Pipelines;
- 2) Installations;
- 3) Communications and Instrumentation;
- 4) Compressor Stations; and
- 5) Meters

and each Asset Class has an assigned Asset Owner.

The approach adopted in the consultation process was, as far as is possible, to review the forecast expenditure under each Asset Class in the context of traditional distribution-related activities in order to link the PC3 forecast spend to the historical PC2 spend.

In summary, BGN had proposed the following distribution Capex for PC3:

• Growth-related Capex	€163.362m
• Replacement Capex	€264.158m
• Non-pipe Capex	<u>€ 24.766m</u>
<b>Total</b>	<b><u>€452.287m</u></b>

## 8.4 Allowed Capex

### 8.4.1 Growth Capex (BGN €163.4m, CER €104.2m)

CER's advisers reviewed BGN's submission for forecast Distribution Growth Capex for the period 2012/13 to 2016/17 and reached the conclusion that the forecast volumes of new growth connections were overly-optimistic based on the outcome of PC2. CER's advisers therefore revised downwards the distribution business's projections to a more realistic starting point for PC3 in 2012/13, and then projected this forward for the remainder of PC3 based on a realistic rate of growth. The CER agrees that the initial projections were overly optimistic and has decided to adopt the revised projections. The CER's final decision on new connection volumes is outlined in Table 16 below, shown in blue.

**Table 16: Estimated new connections volumes (BGN, CER)**

New Connections (Nos)	2012/13	2013/14	2014/15	2015/16	2016/17	Cum
New Housing	1,200	1,650	3,825	4,500	4,500	15,675
	1,440	1,920	2,400	2,880	3,360	12,000
Mature Residential	5,000	5,000	5,000	5,000	5,000	25,000
	3,960	3,960	3,960	3,960	3,960	19,800
Industrial & Commercial	888	926	935	935	935	4,619
	790	829	870	914	959	4,362
Totals	7,088	7,576	9,760	10,435	10,435	45,294
	6,190	6,709	7,230	7,754	8,279	36,162

These adjusted connection numbers were then used as a basis for calculating lengths of main, numbers of services and numbers of meters for the New Housing and I&C growth sectors.

This level of infrastructure build was then translated into a capital expenditure programme. The final regulatory Capex allowances are set out in Table 17.

**Table 17: Growth allowances (BGN, CER)**

€000's	2012/13	2013/14	2014/15	2015/16	2016/17	Cum
Distribution Mains	7,629	8,254	9,943	10,444	10,444	<b>46,714</b>
	6,836	7,492	8,159	9,028	9,720	<b>41,235</b>
Distribution Services	11,838	12,178	13,165	13,459	13,459	<b>64,099</b>
	9,653	10,010	10,373	10,740	11,114	<b>51,891</b>
Distribution Meters	3,778	3,978	4,753	5,035	5,035	<b>22,580</b>
	3,268	3,478	3,694	3,915	4,141	<b>18,496</b>
Customer Contribution	(2,841)	(2,986)	(3,128)	(3,164)	(3,164)	<b>(15,282)</b>
	(2,262)	(2,402)	(2,545)	(2,712)	(2,859)	<b>(12,781)</b>
New Towns Projects	12,662	8,876	-	-	-	<b>21,538</b>
	5,377	0	0	0	0	<b>5,377</b>
Infill Projects	500	3,000	4,000	5,000	5,000	<b>17,500</b>
	0	0	0	0	0	<b>0</b>
Innovation	0	0	0	0	0	<b>0</b>
	-	-	-	-	-	<b>-</b>
<b>Total Growth</b>	<b>34,567</b>	<b>34,550</b>	<b>30,645</b>	<b>32,050</b>	<b>31,550</b>	<b>163,362</b>
	<b>22,872</b>	<b>18,578</b>	<b>19,681</b>	<b>20,971</b>	<b>22,116</b>	<b>104,218</b>

This has resulted in the following downwards adjustments:

- Distribution Mains – a reduction of 12% from a BGN forecast of €46.71m to € 41.23m;
- Distribution Services – a reduction of 19% from a BGN forecast of €64.1m to € 51.9m;
- Distribution Meters – a reduction of 18% from a BGN forecast of €22.6m to €18.5m;
- Customer Contributions – a reduction of 16% from a BGN forecast of €15.3m to € 12.8m;
- New Towns Projects – a reduction of 75% from a BGN forecast of €21.5m to € 5.4m;
- Infill Projects – the removal of BGN's forecast of €17.5m; and
- Innovation Allowance – removal of BGN's forecast allowance (included only as Opex).

Overall, CER's advisers recommendation was to reduce BGN's total growth forecast spend by 36% from a BGN forecast of €163.4m to €104.2m. Having

consider the arguments put forward by the consultants the CER has made the decision to set BGN's total growth forecast spend at €104.2m

#### 8.4.2 Non growth Capex (BGN €264.1m, CER €140.4m)

In terms of Distribution Non-Growth Capex, the CER and its advisers are in agreement with BGN's forecasts with the exception of the Meter Replacement Programme (MRP) for which they assumed the Baseline Scenario (no Smart Meter rollout). CER's decision on the final allowances is summarised in Table 18, with the only deviation from the BGN proposal being under the meter Replacement Programme (MRP).

Please note that the heading under which some of the assets have been classified has changed since the consultation document was published, thus the total under the classifications have changed since the consultation.

**Table 18: Non-growth allowances**

Non-Growth	2012/13	2013/14	2014/15	2015/16	2016/17	Cum
	25,062	33,499	61,820	58,723	38,361	217,465
Distribution Meters <sup>[1]</sup>	20,276	19,013	20,341	16,762	17,332	93,724
	5,588	3,035	3,623	5,294	5,294	22,834
Mains Reinforcement	5,588	3,035	3,623	5,294	5,294	22,834
	813	813	0	0	0	1,626
Mains Replacement	813	813	0	0	0	1,626
	1,121	1,247	1,498	628	628	5,122
Operational Upgrades	1,121	1,247	1,498	628	628	5,122
	4,901	4,905	3,678	1,812	1,817	17,113
Service Replacement	4,901	4,905	3,678	1,812	1,817	17,113
	37,485	43,499	70,619	66,457	46,100	264,160
<b>Total</b>	<b>32,699</b>	<b>29,013</b>	<b>29,140</b>	<b>24,496</b>	<b>25,071</b>	<b>140,419</b>

Notes:

[1] This assumes the 'Baseline Scenario' for Distribution Meters MRP – i.e. no smart metering rollout.

#### Meter Replacement Programme

The above figures allow for the replacement of older meters to ensure that customers continue to receive accurate bills.

### **8.4.3 Facilities and IT (BGN €24.7m, CER €18.6m)**

Expenditure in facilities relates to the capital works associated with the provision of facilities and fleet to support BGN's distribution activities. BGN highlighted a number of cost drivers in PC3, including changes in legislative and regulatory requirements for capital works and maintenance.

In the view of CER's advisers BGN's PC3 submission did not provide sufficient supporting evidence for nearly €4.8m in facilities Capex. The advisers therefore proposed to reduce BGN's transmission facilities Capex by 25%, to a total of €3.6m for the PC3 period.

BGN is seeking an IT Capital Allowance (transmission and distribution) of €39.9m during the PC3 period. IT Capex sought specifically for distribution was €19.98m. The allowance excludes Common Arrangements for Gas (CAG) and European Transmission System Operators Group (ENTSOG), which will be agreed separately with the CER.

IT expenditure was identified in a number of categories, these are outlined and discussed below. CER's advisers' assessed both Capex categories and associated allowable Opex and proposed the following:

- *Market/Regulatory and Care & Maintenance Projects* total €23m: BGN should be challenged to deliver these at €22m.
- *Business Requirement & Business Projects*: BGN should be challenged to deliver key projects for €5.5m
- *Recommended* category: projects proposed are €2.5m.

This gives a total of €30m across transmission and distribution. Using BGN's estimated Opex associated with their level of Capex, this reduced level of Capex at €30m will, by the end of PC3, ensure that Opex remains within the BGN's external consultant's benchmark of 3.3% of turnover.

As such the advisers proposed an IT Capex allowances of €30m over PC3 (transmission and distribution), of which €15m is specifically for distribution. The CER agree with the allowances proposed by the advisors and believe that BGN should be able to provide the necessary IT developments with an allowance of €15m over the period. Therefore the final allowance for PC3 is set at €15m, as shown in Table 19 below.

**Table 19: Facilities & IT**

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Facilities	1,576	1,098	891	633	587	4,784
Facilities	1,182	824	668	475	440	3,588
IT	5,453	4,482	4,096	3,022	2,930	19,982
IT	4,100	3,350	3,100	2,250	2,200	15,000
Total	7,029	5,580	4,986	3,654	3,516	24,766
Total	5,282	4,174	3,768	2,725	2,640	18,588

#### 8.4.4 Smart Metering

A national smart metering programme has been ongoing, under the direction of CER, since 2007. The decision has been taken to proceed to the design stage. At the end of the design stage a decision will be taken on moving to implementation stage. CER is of the view that it is only at that time that the expected costs relating to the gas smart metering will be known. Given that these costs are expected to be known within the next 2 years, the CER has taken the view that it is appropriate to await the development of the detailed design of gas smart metering before making any allowance for the implementation phase of gas smart metering at this time.

The CER published its Smart Metering Decision Paper in July 2012, which outlines that it is proceeding to the next phase of the National Smart Metering Programme for electricity and gas. This Phase 2 will entail development of the smart metering rollout regulatory policy and functional design requirements followed by procurement of the end-to-end solution. The CER will continue to keep the Smart Metering Cost-Benefit Analyses (CBAs) under review as the Programme progresses in order to inform decisions to proceed to subsequent phases. The CER would like to stress that the above replacement is independent to the rollout of smart meters. To the extent that BGN describes these meters as smart ready is a matter for BGN and will not fetter or influence CER in making its decisions relating to the national smart metering programme.

Where these replacement meters are not capable of being used in the smart metering world without any additional cost or obsolescence (and/or where their use leads to negative cost implications for other part of the smart metering programme) will result in the meters not being included as smart meters and

BGN not being able to recover the costs these meters from tariffs. To the extent that these meters will be replaced by smart meters, BGN will be allowed to recover efficient costs where BGN can clearly demonstrate that it had a legal requirement to change old meters for new (in the run up to the national roll out of smart meters) and that the meters were the most cost effective option.

#### **8.4.5 Work In Progress (BGN €1.8m, CER €1.8m)**

The CER has included an allowance for certain items where Work-In-Progress at the end of 2011/12 was not included in the opening RAB for PC3. As they were not included in the opening RAB they were not included in the PC3 revenue calculation.

The items included under distribution relate to Equipment, IT and Metering expenditure which was incurred, but not capitalised.

## 8.5 Summary of Allowed Capex

Table 20 summarises the CER's decision for PC3 Capex.

**Table 20: Distribution Capex allowances (€m, 10/11 prices)**

Category	Dec-13	13/14	14/15	15/16	16/17	Total
Growth						
Distribution mains	6,836	7,492	8,159	9,028	9,720	41,235
Distribution services	9,563	10,101	10,373	10,740	11,114	51,891
Distribution meters	3,268	3,478	3,694	3,915	4,141	18,496
Customer contributions	-2,262	-2,402	-2,545	-2,712	-2,859	-12,780
New towns / Infills	5,377	0	0	0	0	5,377
Innovation	0	0	0	0	0	0
<b>Total Growth</b>	<b>22,782</b>	<b>18,669</b>	<b>19,681</b>	<b>20,971</b>	<b>22,116</b>	<b>104,219</b>
Replacement						
Distribution meters	20,276	19,013	20,341	16,762	17,332	93,724
Mains reinforcement	5,588	3,035	3,623	5,294	5,294	22,834
Mains replacement	813	813	0	0	0	1,626
Operational upgrades	1,122	1,247	1,498	627	627	5,122
Service replacement	4,901	4,905	3,678	1,812	1,817	17,113
<b>Total replacement</b>	<b>32,699</b>	<b>29,013</b>	<b>29,140</b>	<b>24,496</b>	<b>25,071</b>	<b>140,419</b>
Non-pipe						
IT	4,100	3,350	3,100	2,250	2,200	15,000
Facilities	1,182	824	668	475	440	3,589
Smart Meters (WIP)	690	0	0	0	0	690
Equipment (WIP)	1,130	0	0	0	0	1,130
<b>Total non-pipe</b>	<b>7,102</b>	<b>4,174</b>	<b>3,768</b>	<b>2,725</b>	<b>2,640</b>	<b>20,409</b>
<b>Total PC3 Capex</b>	<b>62,583</b>	<b>51,856</b>	<b>52,589</b>	<b>48,191</b>	<b>49,827</b>	<b>265,047</b>

The final Capex allowance for PC3 is **€265m** and is €187m or 41% less than the **€452.3m** requested by the distribution business. The vast bulk of this difference stems from the decision not to allow for smart metering at this time. Other items such as new towns may also be expected to arise over the course of PC3.

The Capex allowance set out by the CER reflects certain assumptions such as load growth and new connection numbers. As seen in PC2 things can turn out to be significantly different. Ultimately, it is the networks business's responsibility to plan and develop the distribution system efficiently. Each of the line items determined above are based on the networks business's submission. During

PC3, it is the networks business that has to determine, in the light of changing circumstances, which projects are progressed, what new work not included in the submission is necessary and efficient and which projects are deferred subject to the overall cap on Capex. The outturn will be reviewed by the CER and only efficient and necessary capital expenditure will be added to the asset base. Notwithstanding this, the CER has requested BGN to draft a procedure through which it will apply for additional funding/revenue allowances for specific items. A non exhaustive list of such items includes smart metering, new towns, unanticipated new large connections, and a substantial increase in standard new connection numbers.

The regulatory guidance for PC2 gave clear ground rules as to how under and overspends of capital expenditure would be treated during the look back at PC2. The subsequent treatment of these under and over spends is evident this decision document. The same guidance will apply for PC3 and the implementation of the review of capital expenditure is expected to be in line with its implementation in this decision.

## 8.6 RAB 2011 to 2015

Based on the above, the distribution RAB for PR3 is set out in Table 21. This is consistent with the final model published alongside this paper.

**Table 21: PC3 distribution RAB**

<b>Figures as per PC3 model (€m, 10/11 monies)</b>					
	<b>2012/13</b>	<b>2013/14</b>	<b>2014/15</b>	<b>2015/16</b>	<b>2016/17</b>
Opening RAB	1,288.5	1,305.8	1,311.1	1,317.1	1,318.9
Closing RAB	1,305.8	1,311.1	1,317.1	1,318.9	1,321.1
Capex	<b>62.9</b>	<b>51.9</b>	<b>52.6</b>	<b>48.2</b>	<b>49.8</b>

## 9.0 Performance & incentives

This revenue control contains a number of mechanisms through which the distribution business is incentivised to improve its performance. Most of these are discussed elsewhere within this document:

- The incentives relating to the cost of County Council Rates, the volume of gas shrinkage, and the cost of safety initiatives are discussed in Section 6.3.7.
- The incentives relating to operating costs are detailed in Section 11.0 of this paper.
- The incentives relating to capital expenditure are detailed in Section 11.0 of this paper.

### **Incentive regarding visits to disconnect**

In the consultation document the CER stated that it was considering the introduction of a specific incentive relating to disconnections. Having noted that suppliers had raised concerns over the number of revisits necessary to disconnect, the CER considered introducing a mechanism where targets would be set for a specific numbers of revisits. The proposal was that the distribution business would still charge suppliers for actual visits, but would receive a separate reward/penalty for exceeding or missing targets.

Alternatively, it was stated that this could be addressed more generally, through the proposal on shrinkage, where an additional allowance would cover a revenue protection unit.

The consultation document requested comments on this area, but the consultation responses did not provide any substantive comments on the issue. Therefore, having considered the matter further, the CER has decided not to implement any such incentive mechanism at this time.

### **Incentive regarding outputs**

In the consultation document the CER stated that it was considering developing explicit performance targets which would reward (or penalise) the distribution

business for delivery (or non-delivery) of specific outputs. While no decision has been made on this matter at this time, it is the CER's intention to consult further on such an incentive mechanism and to put in place incentive mechanisms in time for the 2013/14 tariff period.

## 10.0 Cost of capital

### 10.1 Introduction

The CER selected Oxera Consulting to advise it on cost of capital issues for the gas transmission and distribution price control period (PC3). PC3 covers the period from 2012/13 to 2016/17, and determines allowed revenues for Bord Gáis Networks (BGN), the transmission and distribution asset owner in Ireland. The objective of Oxera's advice was to provide a range for BGN's cost of capital over PC3 in order to help inform the CER's decision.

This analysis of BGN's cost of capital was undertaken in one of the most severe economic downturns in recent decades. The financial crisis that started in 2007, and which led to the collapse of Lehman Brothers, has grown into concerns about the sustainability of governments' fiscal positions across the Eurozone.

These developments have increased the costs of raising capital and, in some cases, have affected the availability and cost of finance for European companies operating in some countries. BGN will, however, need to continue to raise capital at market rates, given its refinancing requirements over PC3. Thus, the analysis of its cost of capital is particularly important if underinvestment is to be avoided.

Credit rating agencies have explicitly linked the credit rating of Bord Gáis Éireann (BGÉ), BGN's parent company, to that of the Irish government, which implies that the deterioration in the creditworthiness of the Irish government and BGN's exposure to the wider economic climate in Ireland would be likely to affect the company's costs of financing. However, the impact on BGN's required rate of return might be expected to be smaller than that on borrowing costs of the Irish government and BGÉ, considering the low-risk nature of regulated networks and the essential nature of their services.

In the consultation document the CER stated that, given the challenges in determining BGN's cost of capital for PC3 caused by macroeconomic conditions in Ireland, it may be appropriate to re-examine the approach set out in order to ensure the cost of capital adequately reflects the latest developments. This section sets out the CER's final decision with regards to the approach adopted

for calculating BGN's cost of capital and the trigger mechanism to be adopted in order to assess the cost of capital in each year of the price control.

## **10.2 Existing Debt**

Under normal economic circumstances the pre-existing debt would not have been taken into consideration when calculating the WACC for the following period. In previous price controls only the prevailing cost of debt would have been considered. However, given the extremely turbulent period recently experienced in international financial market the CER took the view that it was appropriate to depart from standard practice. The CER took the view that the embedded debt on BGÉ's books had been efficiently incurred. The CER therefore considered it appropriate to include this efficiently incurred embedded debt into the calculation of the WACC for the PC3 period.

If the Eurozone crisis prevails over PC3 the question arises as to how embedded debt might be treated in PC4. If by the start of PC4 the crisis has passed, would the cost of (presumably expensive) historic debt be taken into account in calculating the WACC for PC4?

Subject to these financiability duties the CER intends to return to the standard practice as soon as possible. While the CER cannot bind future decision makers, the CER expects that when it is setting the cost of debt for PC4, the cost of efficiently incurred embedded debt will similarly be included in the cost of the WACC for the PC4 period. There are many uncertainties over the next period, for example the Eurozone crisis might pass into history quickly, in which case it may be appropriate to revert to standard practice for PC4. On the other hand the crisis might prevail for an extended period during PC3. In any event the CER will take its financeability, duties into account in setting the appropriate WACC for PC4.

## **10.3 Methodological framework**

The estimates of the cost of capital presented in this report include an adjustment to the cost of equity and cost of debt in order to take into account the risks associated with the Eurozone crisis—this is termed the 'crisis premium' (CP). There is not one widely accepted methodology that can be used to quantify the risks associated with the Eurozone crisis in the cost of capital for companies

operating in countries where there are concerns around the sustainability of government's fiscal positions. However, the approach adopted here is consistent with key academic and empirical papers on this topic.

The CER's approach in previous price control reviews has been to update the cost of capital parameters for BGN every four to five years, in order to reflect changes in capital markets. This process enables movements that lead either to an increase or decrease in the cost of capital parameters to be reflected in revised estimates of the cost of capital on a periodic basis.

At a time of very volatile conditions, there is a need for a more appropriate approach, given the CER's financing duty and the need to protect consumers. Given the unstable market conditions in the Eurozone at present, in order to safeguard consumers' interests and ensure BGN's financeability, a trigger mechanism was proposed in the consultation document, whereby the allowed cost of capital is adjusted if there are significant changes in market conditions in Ireland. The aim of this proposal was to ensure that, if market rates rise, the allowed cost of capital would be adjusted, providing BGN with protection against capital market risk. Conversely, should market rates fall, the benefits of lower financing costs would be passed through to consumers sooner than under the current regulatory regime in PC2.

The cost of capital parameters that are subject to the trigger mechanism need to be estimated using a relatively short averaging period to ensure that movements in capital markets are captured, but not too short to ensure that parameters are not overly affected by any short-term deviations from fundamental values caused by volatile market conditions. During the consultation process consideration was given as to what the appropriate allocation of risk between BGN and consumers, given the current market environment. An averaging period of several years would have been too long to capture current market conditions, while a period of a few weeks or months may have been too short given the volatile market conditions. Overall, in view of these considerations, the CER's advisers proposed that an averaging period of one year would appear to strike the right balance.

The CER agrees that, on balance and given the current market environment, one year appears to be the most appropriate time period and has decided to adopt

this for the duration of PC3. However, the CER does not consider this to represent a permanent change in its regulatory approach. The measures are intended to be implemented for the duration of PC3 in order to deal with the significant uncertainty resulting from the ongoing developments in the Eurozone and its effects on the Irish financial markets. At the point of consideration of the arrangements for PC4, should conditions have changed, then the CER will at that point consider whether the continued application of this framework is appropriate.

## 10.4 Range for BGN's cost of capital

The consultation document set out the estimate of BGN's real pre-tax cost of capital as being 5.8–7.6%, as shown below.

	Range for the parameters
Real risk-free rate and the crisis premium (%)	3.5–5.5
Debt premium (%)	redacted
<b>Real pre-tax cost of new debt (%)</b>	<b>redacted</b>
<b>Real pre-tax cost of existing debt (%)</b>	<b>redacted</b>
<b>Real pre-tax cost of debt (%)</b>	<b>3.8–4.9</b>
<b>Real post-tax cost of debt (%)</b>	<b>3.3–4.3</b>
Real risk-free rate and premium for risks associated with the Eurozone crisis (%)	3.5–5.5
Asset beta	0.35
Equity beta	0.78
Equity risk premium	4.5–5.0
<b>Real post-tax cost of equity (%)</b>	<b>6.9–9.2</b>
<b>Real pre-tax cost of equity (%)</b>	<b>8.1–10.8</b>
Gearing (%)	55
Corporation tax (%)	12.5
<b>Real post-tax cost of capital (%)</b>	<b>4.9–6.5</b>
<b>Real pre-tax cost of capital (%)</b>	<b>5.8–7.6</b>

Note: The real pre-tax cost of debt is estimated as a weighted average of the cost of new debt and the cost of existing debt on the basis of [redacted]. The weight on the cost of new debt reflects the proportion of debt to be refinanced over PC3 (ie, [redacted]). The weight on the cost of existing debt is [redacted]. The real post-tax cost of equity has been estimated as the sum of the risk-free rate, the premium for risks associated with the Eurozone crisis and the multiple of the equity beta and the equity risk premium. To ensure the appropriate treatment of tax, the conversion between the post- and pre-tax cost of equity has been undertaken in nominal terms. The real post-tax cost of equity has been converted into a nominal post-tax cost of equity using the European Central Bank's long-term target for inflation. The nominal pre-tax cost of equity is calculated as the nominal post-tax cost of equity, divided by 1 minus the corporate tax rate. The nominal pre-tax cost of equity is then converted into a real pre-tax cost of equity using the European Central Bank's long-term target for inflation. It will be important to ensure that the resulting estimate of the real pre-tax cost of capital is applied consistently.

Source: Oxera analysis.

Although the above estimate of BGN's cost of capital is higher than the CER's assumptions for PC2, this is predominantly driven by the recognition of the risks associated with the Eurozone crisis. There is clear evidence to show that BGN's cost of financing has increased as a result of the conditions in Irish markets.

The final ranges for the individual parameters have been determined as follows.

### **Real risk-free rate and premium for risks associated with the Eurozone crisis**

Some commentators have suggested that observed declines in estimates of the risk-free rate is associated with a flight to quality. The assessment therefore considers the risk-free rate and the impact of the Eurozone crisis jointly, as there are arguments to suggest that the low risk-free rate observed in some Eurozone countries is related to higher government debt yields and corporate bond yields in other countries.

Since the November 2010 bailout of the Irish government, yields on Irish debt have increased, following a number of downgrades to the state's credit rating. Although yields have recently fallen, yields on Irish government debt remain higher than before the start of concerns about the sustainability of government's fiscal positions. This suggests that yields on Irish government bonds cannot be used as a proxy for rates on a 'risk-free' investment. Instead, yields on German and Dutch government bonds are considered, with the trigger mechanism providing protection against rises or falls in the risk-free rate.

Nominal yields on government bonds in Germany and the Netherlands have fallen since 2008. This is likely to be due to a combination of factors, such as the European Central Bank's monetary policy and increased demand by investors for German and Dutch government bonds, in particular, relative to other asset classes.

The CP for debt is estimated based on yields on investment-grade utility corporate bonds in Ireland less the equivalent yield on bonds with a similar credit rating that are issued by companies operating in countries used as a proxy for the risk-free rate estimate (Germany and the Netherlands).

While the cost of equity compensates investors for a different set of risks than the cost of debt, considering that equity investors have a residual claim on a company's cash flows, the additional premium for risks associated with the Eurozone crisis required by equity investors might be expected to be of a similar size to the additional premium required by debt investors. For these reasons as well as the CER's duty to finance, a CP has also been added to the cost of

equity. The CP added to the cost of equity is of the same magnitude as that added to the cost of debt. This approach effectively assumes that the extra risk of investing in the Irish equity market compared with, for example, the German or Dutch equity market, can be approximated by differences in the default premium paid by Irish companies relative to German or Dutch companies with the same credit rating. The CER's advisers considered this approach reasonable given the data available to estimate the CP in the current context.

On this basis, an estimate that reflects the combined impact of the risk-free rate and the premium for the risks associated with the Eurozone crisis amounts to 3.5–5.5%.

### **Equity risk premium**

Since the impact of risks associated with the Eurozone crisis is captured through an explicit adjustment to the cost of capital, it is important to ensure that, in the ERP estimates, there is no double-counting. On the basis of historical estimates combined with forward-looking estimates from the dividend growth model, as well as surveys of academics and professionals, and regulatory precedents, an appropriate range for the ERP is 4.5–5.0%.

### **Asset beta**

As BGN is not listed, comparator companies were selected that focus predominantly on either gas transmission or gas distribution activities, and that operate in countries where there are minimal concerns about the sustainability of government's fiscal positions. On this basis, estimates of BGN's asset beta range from 0.3 to 0.4. For the purposes of the calculation of the cost of capital, a point estimate for the asset beta of 0.35 is adopted.

### **Gearing**

To reflect the CER's statutory duty to ensure the financeability of BGN, financial ratios are targeted that are consistent with an investment-grade credit rating. On this basis, the evidence suggests that maintaining the CER's current gearing assumption of 55% is appropriate.

### **Cost of debt**

BGN's cost of debt has been estimated as a weighted average of the cost of new

debt and the cost of existing debt over the price control period, taking into account BGN's refinancing requirements. The cost of existing debt reflects the lower rates locked in at a time of relatively more benign conditions. As BGN will need to access capital markets during PC3, the cost of new debt incorporates the CP. On the basis of a weighted average of the cost of new debt and the cost of existing debt, the estimate of BGN's pre-tax cost of debt ranges from 3.8% to 4.9%.

### **Selecting a point estimate within the range**

The selection of the appropriate point estimate within the range for BGN's cost of capital is critical in order to reflect the required rate of return on the capital already invested in the business, its future refinancing, as well as the need to raise new capital for future investment. Furthermore, given the lack of public listing for BGN, caution needs to be exercised when choosing the point within the range.

However, these factors need to be viewed in conjunction with an explicit allowance in the cost of capital for the risks associated with the Eurozone crisis, as well as the introduction of a trigger mechanism that protects BGN against adverse movements in financial markets. The introduction of a trigger mechanism means that less headroom needs to be accommodated in the estimates of some of the individual parameters than otherwise.

Taking into account the above factors, at the time the consultation paper was published CER's advisers recommended introducing a point estimate for the cost of capital at the midpoint of the range, which would have set a real pre-tax cost of capital of 6.7%. However, since the publication of the consultation document there has been a significant change in the yields on Irish debt. Taking on board the lower yields and applying this to the approach and Trigger Mechanism set out below the CER have set a WACC of 6.39%.

## **10.5 Trigger Mechanism**

In the context of market uncertainty, regulation can be designed to account for unexpected changes in specific cost of capital parameters, whilst retaining the important characteristics of transparency and objectivity. In light of current levels of uncertainty around future economic conditions in the Eurozone setting a fixed

cost of capital would likely mean that a high figure would be in place for all of the five years, regardless of any changes in economic conditions. It would also leave significant risk with BGN entirely. The consultation document set out that in the context of CER's financing duty and the additional cost that would be faced by consumers (even if the economic environment improved), setting a cost of capital for five years may no longer be appropriate. It was proposed that a trigger mechanism be adopted in order to allow changes to the cost of capital during the five year period. In the consultation response document some respondents questioned the floor and ceiling set out in the consultation document, however several respondents also stated that they recognised the merit for the introduction of a trigger mechanism and viewed the range proposed as being reasonable. The CER has decided that it will adopt the mechanism set out in the consultation document involving a floor and ceiling on the WACC with a trigger mechanism that instigates a change in the rate applied.

The trigger mechanism aims to ensure that, if market rates rise, the allowed cost of capital would be adjusted, providing BGN with protection against capital market risk. Conversely, should market rates fall the benefits of lower financing costs would be passed through to consumers sooner than under the current regulatory regime in PC2.

- **A trigger mechanism**, whereby the allowed cost of capital (or some component thereof) is adjusted for movements in some clearly defined benchmark beyond (ie, above or below) some pre-determined threshold. To enable a trigger approach to capture extreme market movements while at the same time minimising the number of times a threshold is reached, an appropriate averaging period needs to be adopted.
- The cost of capital parameters subject to a trigger would need to be estimated based on a relatively short averaging period to ensure that extreme movements in capital markets are captured, but not too short to ensure that parameters are not overly affected by any short-term deviations from fundamental values caused by volatile market conditions. This would be most important for the cost of debt parameter, given the CER's financeability duty and the recently highly volatile conditions in debt markets.
- Ultimately, the decision on which averaging period to use relies on a

degree of judgment. An averaging period of several years would probably be too long to capture current market conditions, while a period of a few weeks or months may be too short given the volatile market conditions. Overall, given these considerations, the CER has decided that an averaging period of one year strikes an appropriate balance, as set out in Section 10.2 above.

However, in the event of extreme changes in market conditions, such as the collapse of the euro, it may be appropriate to consider alternative approaches. The steps outlined in the remainder of this section assume that, while there may be changes in market conditions, these changes will not be extreme.

### **10.5.1 Illustration of the design of the trigger mechanism**

In essence, the design of the trigger mechanism reflects the implied changes in the cost of new debt and equity financing that arise as a consequence of developments in capital markets. The change in the cost of capital under the trigger mechanism in response to changes in Irish government yields should alter by an amount that reflects this. The estimates presented in this section represent the required adjustment to fully reflect estimates of the change in financing costs, in so far as they apply to either the cost of new debt or equity financing.

#### **Floor and ceiling**

The observed historical relationships from capital markets need to be interpreted carefully, in light of the volatility in financial markets. The design of the trigger mechanism, however, recognises within reasonable bounds, the broad nature of the relationship between Irish government yields and the underlying estimate of BGN's cost of capital.

The mechanism is based on statistics on the observed relationship between changes in market conditions and estimates of BGN's cost of capital. Because the relationship is likely to change as the underlying variables move to extremely low or high values, a floor and a ceiling have been imposed.

The rationale behind the choice of the floor is to reflect a plausible estimate of the cost of capital in the event that macroeconomic conditions in Ireland continue to improve, and the Eurozone problems continue to dissipate. As it is not possible to

observe this data, as of yet, the choice of the floor inevitably involves some degree of judgement. The allowed cost of capital for PC2 (of 5.2%) was selected as the value for the floor, as this reflects an established reference point for an estimate of BGN's cost of capital under more benign conditions (ie, as of 2007 when the cost of capital for PC2 would have been estimated)<sup>17</sup>. The cap has been designed symmetrically, with a ceiling of 8.2% (similarly 1.5% higher than Oxera's midpoint estimate of the cost of capital of 6.7%)<sup>18</sup>.

### **Degree of risk sharing**

Consideration has been given to the appropriate degree of risk sharing between BGN and its customers, and the consequences of any potential over- or under-shooting in response to changes in the capital markets. This inevitably involved a degree of judgement about the appropriate allocation of risk between customers and consumers.

The design of the trigger mechanism assumes that changes in capital market conditions partly feed through into the cost of equity and cost of new debt. This approach is justified on the basis that expected returns for regulated energy networks, such as BGN, are likely to be less affected by concerns about the sustainability of government's fiscal positions than returns on government bonds. In light of the volatility in capital market data for government yields and BGE's bond yields, it is difficult to determine a precise estimate of the extent to which changes in debt markets influence utilities' cost of capital. However, the analysis of the premium due to risks associated with the Eurozone crisis (CP) suggests that the CP estimated on the basis of corporate bonds is approximately 60% of the CP based on government bonds.<sup>19</sup> This estimate of 60% is considered to

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<sup>17</sup> Alternative approaches that could have been adopted to define the floor would have been to use average yields on Irish government bonds or BGE's yields; however, these approaches arguably involve a far greater degree of arbitrariness. On the basis of the CER's projections for PC3, it has been checked that BGN would be financeable on the basis of efficient costs and notional financing with a cost of capital of 5.2%.

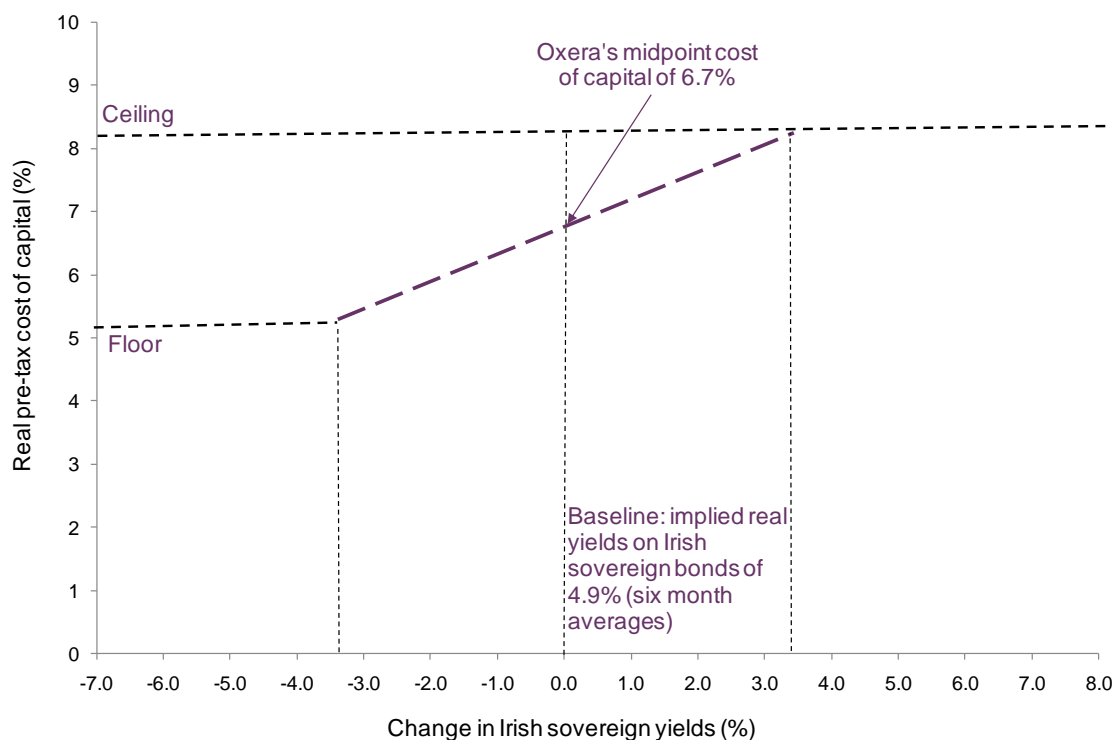
<sup>18</sup> The choice of the floor of 5.2% is 1.5% lower than Oxera's midpoint estimate of the cost of capital of 6.7%.

<sup>19</sup> This is based on the ratio of the 1-year average of the ECP estimated from corporate bonds relative to the CP estimated on the basis of government bonds (as outlined in Table A1.9 in

represent a conservative estimate of the relationship between Irish government yields and BGE's bond yields. In light of the uncertainty around the precise magnitude of the relationship, it is important to ensure that the estimate of the cost of capital resulting from the application of the trigger mechanism is not overly sensitive to changes in Irish government yields, as this might lead to the cost of capital being under- or over-estimated.

The trigger mechanism therefore translates a proportion (specifically, 60%) of the change in Irish government yields onto the cost of new debt and equity. On the basis of this methodology, a 1% change in Irish government yields (under the design of the trigger mechanism) would lead a 0.44% change in the cost of capital. This 0.44% more accurately represents the slope, as per Figure 2 below, than the 0.4% detailed in the Oxera document.

Figure 2 illustrates the sensitivity of the estimate of the cost of capital to the change in Irish government yields under the trigger mechanism design.



**Figure 2: Summary of the trigger mechanism design**

Note: The floor and ceiling are defined as 5.2% and 8.2% respectively. The floor is 1.5% below Oxera's midpoint estimate of BGN's cost of capital of 6.7%. The ceiling is defined symmetrically, as 1.5% higher than Oxera's midpoint estimate of BGN's cost of capital.

Source: Oxera analysis.

As a check on the appropriateness of the workings of the trigger mechanism, Table 22 compares the resulting estimates of the cost of capital under the trigger mechanism with bottom-up estimates of BGN's cost of capital (on a parameter-by-parameter basis) on the basis of the following scenarios:

- spot rates as of March 2012 continue to persist; and
- conditions in Ireland return to more benign conditions.

**Table 22: Comparison of bottom-up estimates of the cost of capital with estimates of the cost of capital from the application of the trigger mechanism**

	Spot rates (%)	Benign conditions (%)
<b>Irish sovereign yields (implied real)</b>		
Baseline (6-month averages)	4.9	4.9
Irish sovereign yields (implied real)	3.1	1.6
Change in Irish sovereign yields from baseline	-1.8	-3.3
<b>Estimated cost of capital (WACC)</b>		
Estimated bottom-up WACC	6.1	5.2
Estimated WACC under trigger mechanism	5.9 <sup>1</sup>	5.2 <sup>2</sup>

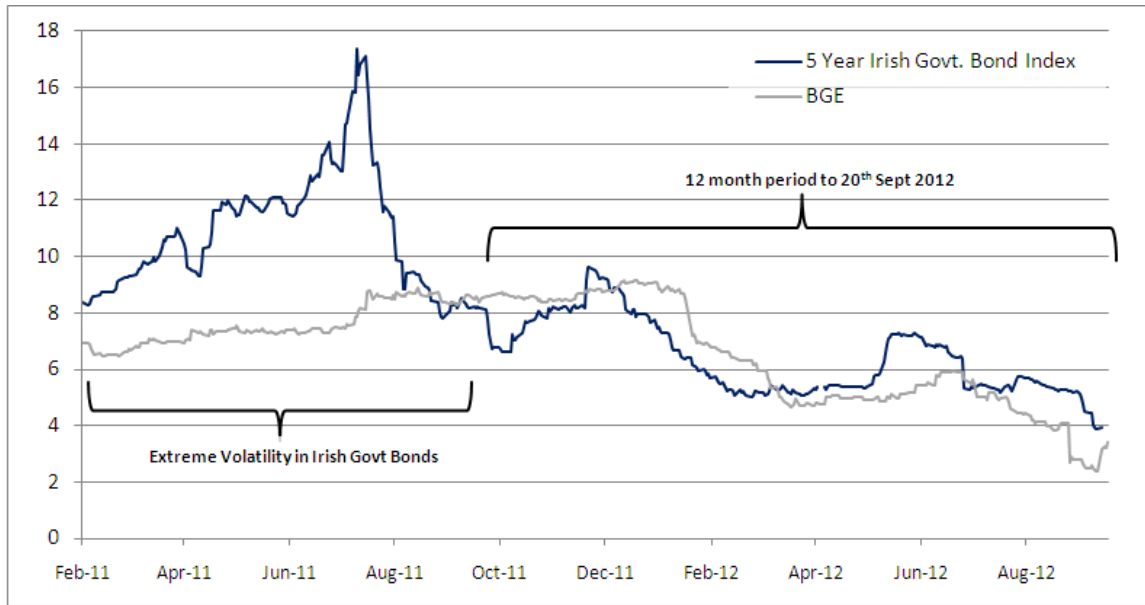
Note: The baseline is estimated over the period from September 16th 2011 to March 16th 2012. The estimated bottom-up WACC reflects an estimate of the cost of capital calculated on the basis of each parameter, rather than by the application of the trigger mechanism. Under the 'spot rates' scenario, the estimated bottom-up WACC is based on spot data as of March 16th 2012. Under the 'benign conditions', the estimated bottom-up WACC is based on data from April 16th 2009 to April 16th 2010. <sup>1</sup> Under the 'spot rates' scenario, the estimated cost of capital is calculated as  $-1.8 \times 0.4 + 6.7$ ; it should be noted that due to rounding, the results may differ slightly from the more detailed estimates presented in **Error! Reference source not found.** <sup>2</sup> The mechanism reaches an estimate close to the floor, but not at the floor. Estimates of the pre-tax real cost of capital are presented.

Source: Oxera analysis.

As shown in Table 22 the resulting estimates of the cost of capital under the trigger mechanism design are very close to the detailed bottom-up estimate of the cost of capital in both circumstances. Moreover, in the event that Irish government yields revert to previously observed lower levels, the trigger mechanism would lead to an estimate of the cost of capital that aligns very closely with the value adopted previously for PC2.

## 10.6 Recent data

Oxera's assessment of the cost of capital was based on market evidence up to January 31st 2012. However, since the assessment was undertaken in early 2012, yields on Irish Government debt and BGE's bond have declined (as shown in Figure 3).



**Figure 3: Evolution of nominal yields on Irish government bonds and BGE's bond**  
Source: Bloomberg (Irish Govt. Bond) & Reuters (BGE)

As can be seen from Figure 3 the yields on Irish Government bonds have fallen significantly in recent months. Figure 3 uses Bloomberg data to illustrate the movement in Irish 5 year Government bonds. As set out below, a Bloomberg index (Sedol -GIGB5YR) has been chosen as the benchmark index to measure changes in Irish 5 year Government bonds.

As set out above the CER has decided that an averaging period of one year is appropriate to measure the yield. In their report Oxera used data covering the period 16<sup>th</sup> September 2011 to 16<sup>th</sup> March 2012. When this period is applied to the Bloomberg Sedol set out above, it results in an implied real yield on Irish Government bonds of 5.105%. To examine the impact of recent movements on the cost of capital, the average implied real yield on Irish Government bonds for the twelve months to the 17<sup>th</sup> September 2012 has been taken. This resulted in the average yield reducing to 4.399%. When this is applied to the trigger mechanism, as outlined in Figure 2 above and Section 10.6 below the result is a reduction in the WACC from 6.7% to 6.39%. The CER has decided to apply the 6.39% rate for the first year of PC3.

## 10.7 Application of Trigger Mechanism

The CER has decided that the most appropriate trigger mechanism to use is the movement in the real yields of Irish sovereign bonds. As set out above the

expected returns for regulated energy networks, such as BGN, are likely to be less affected by concerns about the sustainability of government's fiscal positions than returns on government bonds, therefore the use of such bonds for the trigger mechanism is the most appropriate approach. In addition it provides a clear and transparent methodology.

Figure 2 above shows the range in which the WACC could move depending on the changes in the real yields on Irish sovereign bonds. In order to be as transparent as possible the CER is taking a publicly available index of 5 year Irish Government Bonds and will use these to track any changes in the yields from year to year. The Bloomberg code or Sedol for the index is GIGB5YR and this is available to all subscribers to Bloomberg.

When the annual review of BGN Distribution Tariffs is conducted the CER will evaluate the change in Irish government bond yields to see whether a change in the WACC for the following tariff year is required. As set out above an averaging period of one year is the appropriate time period to take. Therefore when conducting the annual review the CER will use a twelve month period, with the most up to date information available as the averaging period.

With a base of 4.399% feeding through to the calculation at the start of the process the resulting WACC for the five year period is 6.39%. Any movements away from this 4.399% yield would impact the WACC, as illustrated in Table 23 below, which shows how the change in yield impacts on the WACC.

The table shows a rounded version of the calculation. As can be seen, highlighted green, the 5.105% yield for the six months to 16<sup>th</sup> March 2012 translates to the mid-range WACC of 6.7%, The 4.399% calculated based on the twelve months to 17<sup>th</sup> September 2012, highlighted in blue, translates to the 6.39% to be applied at the start of PC3.

**Table 23: Change in the implied real yields on Irish sovereign bonds**

Yield	WACC	Yield	WACC	Yield	WACC	Yield	WACC
1.7%	5.20%	3.5%	5.99%	5.3%	6.79%	7.1%	7.58%
1.8%	5.24%	3.6%	6.04%	5.4%	6.83%	7.2%	7.63%
1.9%	5.29%	3.7%	6.08%	5.5%	6.88%	7.3%	7.67%
2.0%	5.33%	3.8%	6.13%	5.6%	6.92%	7.4%	7.71%
2.1%	5.38%	3.9%	6.17%	5.7%	6.96%	7.5%	7.76%
2.2%	5.42%	4.0%	6.21%	5.8%	7.01%	7.6%	7.80%
2.3%	5.46%	4.1%	6.26%	5.9%	7.05%	7.7%	7.85%
2.4%	5.51%	4.2%	6.30%	6.0%	7.10%	7.8%	7.89%
2.5%	5.55%	4.3%	6.35%	6.1%	7.14%	7.9%	7.94%
2.6%	5.60%	4.4%	6.39%	6.2%	7.19%	8.0%	7.98%
2.7%	5.64%	4.5%	6.44%	6.3%	7.23%	8.1%	8.02%
2.8%	5.69%	4.6%	6.48%	6.4%	7.27%	8.2%	8.07%
2.9%	5.73%	4.7%	6.52%	6.5%	7.32%	8.3%	8.11%
3.0%	5.77%	4.8%	6.57%	6.6%	7.36%	8.4%	8.16%
3.1%	5.82%	4.9%	6.61%	6.7%	7.41%	8.5%	8.20%
3.2%	5.86%	5.0%	6.66%	6.8%	7.45%		
3.3%	5.91%	5.1%	6.70%	6.9%	7.49%		
3.4%	5.95%	5.2%	6.74%	7.0%	7.54%		

Taking the average implied real yield on Irish Government bonds for the twelve months to the 17<sup>th</sup> September 2012, the WACC for the 2012/13 tariff period has been set at 6.39%. The CER recognises that there is likely to be some continued volatility in bond yields over the next few years and does not wish to change the WACC unless there is a measured change in Irish bond yields. Therefore a 0.5% change in the real yields on Irish sovereign bonds is being set as the threshold which must be reached before any change is made to the WACC in future years.

Should this threshold be reached when the CER evaluates the yields annually then the appropriate change in the yield will feed through to the WACC, as indicated in Table 23 above, and the new WACC will apply for the following tariff year. In any subsequent years the threshold will remain, or in other words there must be a year on year change of 0.5% or more in the yield Irish sovereign bonds before the WACC for the subsequent tariff year is adjusted.

## **10.8 CER Decision**

The CER recognises that the current economic conditions have led to a more difficult environment for Irish semi-states including BGN to finance their activities. This means that the tariffs faced by customers during PC3 will be higher than would otherwise have been the case. While this is regrettable, it is an inevitable consequence of the economic market conditions. The CER has included an adjustment mechanism to ensure that, if economic conditions improve, consumers will not continue to be faced with this higher cost over the remainder of the control period.

The final CER decision is to adopt a cost of capital of 6.39% with an adjustment mechanism as outlined above.

## 11.0 The form of the control

This section describes the overall form of the price control, specifying the approach taken by the CER and how the base and subsequent year revenues have been determined.

### 11.1 Structure of the price control

The CER believes that the price control for distribution business should be consistent with previous price controls. Applying different principles or models for each price control would risk creating an inconsistent set of incentives and uncertainty. Therefore, for the purposes of PC3, the CER has substantially retained the model used in PR2.

The PC3 model contains:

- Incentive regulation based broadly on the RPI-X model;
- A retention of benefits achieved through costs lower than target levels.
- A factor to account for changes in the number of customers from expected levels.
- Uncertain costs will be reviewed on a case by case basis by the CER.
- Pass-through costs should be kept to a minimum. Incentives to minimise pass-through will be applied where practical.
- The 'k' factor and inter-year adjustments as being broadly the same as in the existing price control.

The CER's position on each of the above is set out below in turn.

#### 11.1.1 Incentive regulation

The CER has decided to continue the application of an incentive based approach. Efficiencies are built into the Opex and Capex allowances and the resulting revenue is profiled over the period.

#### 11.1.2 Benefit retention

The distribution business will not be compensated for any overspends on operating expenditure during the period. It will be allowed to retain any under spends on operating costs during the period.

Regarding capital costs, the same mechanisms as those employed during PC2 is to be used for PC3.

### **11.1.3 Cost Drivers**

The current price control formula contains a cost driver based on customer numbers. This is to be retained as the sole cost driver for PC3.

### **11.1.4 Uncertain costs**

Uncertain costs are defined as those that could not reasonably be foreseen by the distribution business. The CER has decided that such costs should be dealt with on a case-by case basis. In each case, the distribution business would be expected to ensure that changes in Opex or new Capex would take place in an efficient manner and this would be reflected in the allowance provided – that is, there would not be an automatic pass-through of such costs.

### **11.1.5 Pass-Through Items**

The previous price control contained a provision for the pass-through of certain types of costs, such as business rates, that are deemed to lie outside the business's control. The CER will continue to use this approach.

In some cases pass through items are subject to incentive mechanisms which shares savings between the distribution business and the network customers, for example, in areas such as rates and safety.

### **11.1.6 Inter-year Adjustments for over or under recovery**

The CER is to retain the current one-stage 'k' factor mechanism for PC3.

## **11.2 Profiling & indexation**

### **11.2.1 Profiling**

The tariffs for 2012/13 have been already set, the CER has profiled the revenue by allowing a step change in when moving to year two of the control and no real change thereafter.

### **11.2.2 Indexation**

The model used by the CER uses a base allowable revenue which is indexed to take account of price inflation. The index used should be the best reflection of the increases in prices faced by the distribution business, such as wage inflation or materials inflation etc. Also the index needs to be practical to implement, robust and transparent.

In the first review of allowable revenues for BGÉ Networks as gas transmission and distribution network operator the CER used CPI and in the second review HICP was used. The CER has decided to continue using HICP for the course of PC3.

The CER accepts that no one index can precisely mirror the distribution businesses input costs. It is also accepted that the majority of the annual revenue which the distribution business receives covers depreciation and return on its asset base, rather than operating costs.

It is worth noting that the CER is not necessarily of the view that the use of this indexation mechanism results in additional efficiencies being built into the distribution business's allowed revenue. Those are separately built into the allowances.

## **11.3 Revenue control formula**

### **11.3.1 Introduction**

During the control period, and consistent with the previous controls, yearly updates would be completed as detailed below. During the previous controls the CER consulted on these yearly updates. The consultation paper set out the CER's proposal to cease holding formal consultations during the PC3 period and instead to publish an information note outlining the effect of implementing the yearly updates. Respondents were asked to comment on this proposal.

No objections were raised from any respondents and therefore for the forthcoming control the CER will not hold a formal consultation, but will publish an information note outlining the effect of implementing the yearly updates detailed

below.

The formula is as follows:

$$R_t = \prod_{j=2010/11}^t \left[ (1 + Inf_j) / 100 \right] * B_t + \Delta P_t + \Delta U_t + K_{t-2}$$

**Equation 1: Revenue formula for each year within PR3 period**

Where:

- $R_t$  is the maximum level of revenues allowed in the period  $t$  and the revenues on which the next years tariffs are based. It is expressed in nominal (i.e. year,  $t$ ) euro million (‘€m’) terms.
- $Inf_j$  is the percentage change in the Irish (all-items) Harmonised Index of Consumer Prices (HICP) for the 12-month period April to March in the year  $j$ . Where  $j > t$ ,  $HICP_j$  is a forecast value (i.e.  $HICPF_j$ )<sup>20</sup>.
- $B_t$  is the level of allowed revenues in real 2010/11 gas year prices for the distribution business in year  $t$ . It is expressed in €m.
- $\Delta P_t$  is the forecast level of pass through costs less the level of pass through costs on which initial allowed revenues ( $B_t$ ) were originally set. It is expressed in nominal (i.e. period  $t$ ) €m<sup>21</sup>.
- $\Delta U_t$  is the change in uncertain costs. These may include costs associated with regulatory or legislative changes, etc
- $K_{t-2}$  is the correction factor which adjusts revenues in year  $t$  to reflect the difference between expected outturn values and actual outturn values in

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<sup>20</sup> March (year  $t$ ) inflation figures are usually available in the June (year  $t$ ) publication. This is the data that the CER will use in the revenue calculation. If this data is not available, the CER will use its discretion to identify another appropriate measures of Irish HICP.

<sup>21</sup> Please note that in the first year of the revenue control period (2012/13)  $PF_t = 0$ .

year t-2, with interest payments (and penalties for over or under-recovery) added on.

In each year of PC3 the CER will adjust the model for any additional increases in cost which BGN must efficiently incur (a materiality threshold will apply). The additional costs (Capex & Opex, as appropriate) will be submitted in the monies of the day and indexed back to 2010/11 monies, using the relevant inflation factors. The relevant amounts of Capex and Opex in 2010/11 monies will be input in to the model, this will allow adjustment of the level of allowed revenues for each year.

### Correction Factor $K_{t-2}$

$K_{t-2}$  adjusts revenues for differences between expected outturn values and actual outturn values. If  $K_{t-2}$  is more than 105% or less than 95% of  $B_t$  then the amount above 105% or below 95% would be carried over and added to  $K_{t-2}$  in the subsequent year.

This correction will:

- Correct for the difference between indexation forecast for the year t-2 when originally setting the revenue for that year and the outturn indexation
- Correct for the difference between the number of customers that were forecast to connect to the system in year (forecast when originally setting the revenue for that year) and the outturn number of customers.
- Correct for the difference between the revenue that was set for collection for the year t-2 when originally setting the revenue for that year and the outturn revenue that was collected.
- Correct for the difference between the level of pass through costs that were set for the year t-2 when originally setting the revenue for that year and the outturn values. In some cases, all of the difference will be passed through, in other cases only 50% will be passed through. The different treatments are documented in Section 6.3.7.
- Correct for the difference between the level of uncertain costs that were set for the year t-2 when originally setting the revenue for that year and the outturn values.
- Adjust the above factors by:
  - the average nominal Euribor rate in the year t-1 plus 2%; and,

- the average nominal Euribor rate in the year t-2 plus 2%.

This will ensure that the appropriate amount (relating to year t-2) is included within the revenue to be recovered in year t.

The above 'plus 2%' will be applied if recovered revenues are below 103% of allowed revenues. Any over-recovery above 103% will attract a charge of the Euribor rate 'plus 4%'.

## **12.0 Conclusion**

This paper sets out the CER's decisions on the revenue that the distribution business should be allowed to collect from its customers over the October 2012 to September 2017 period. The CER has decided to allow €996m to BGN for distribution over the period of PC3.