COMMISSION FOR ENERGY REGULATION

GAS TRANSMISSION AND DISTRIBUTION REVENUE CONTROL

PC3 TRANSMISSION OPEX AND CAPEX REPORT

May 2012

FOR PUBLICATION

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1. INTRODUCTION

1.1. Purpose

A consortium of CEPA, GL Noble Denton and PKF (UK) LLP (PKF) has been engaged by the Commission for Energy Regulation (CER) to advise on Bord Gais Network's (BGN) transmission and distribution allowed revenue controls for Price Control period 3 (PC3).

This paper provides our analysis of the *transmission* revenue control including our assessment of BGN's outturn (historic) capital expenditure (capex) and operating expenditure (opex) and our proposals for capex and opex allowances in PC3.

1.2. Approach followed

The consortium has taken a bottom-up and top-down approach to establish our view of the efficient cost path for BGN's transmission business. First we reviewed each aspect of BGN's proposed opex and capex to assess whether the expenditure is required for the efficient operation of BGN's transmission business and the future development of the network. This bottom-up assessment was then cross-checked with a top-down assessment of BGN's transmission business based on information provided by BGN and a review of trends in other regulated sectors.

For our bottom-up assessment, the objective has been to develop a base year of normalised transmission opex costs that represents the core historic "business as usual" opex and which can then be revised to reflect additional items of core opex forecast to be incurred in future years. Our normalised costs have been 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 consideration of the impact of allocation and related party profit issues.

To determine on required capex, first we reviewed the capex plans submitted by BGN including the company's forecasts of demand and new connections. This included a review of drivers of capex in PC3 and the technical needs case presented by BGN. We also considered how categories of capex (for example, IT) might support achievable opex savings over the price control (for example, in areas such as business support services). Based on our assessment, a series of bottom-up adjustments were made to BGN's capex plans.

As part of the opex review, we also considered trends and regulatory allowances for input price inflation. This included a review of available evidence of wage-inflation in Ireland (as part of our bottom-up assessment) and allowances made for input price inflation in recent GB price control reviews[1] (as part of our benchmarking analysis).

Specifically we considered the need for a Real Price Effect (RPE) allowance – this is the level of changes in input prices (e.g. wages) relative to a measure of general price inflation, such as the

[1] For example, the current price control for the gas distribution network operators in GB.

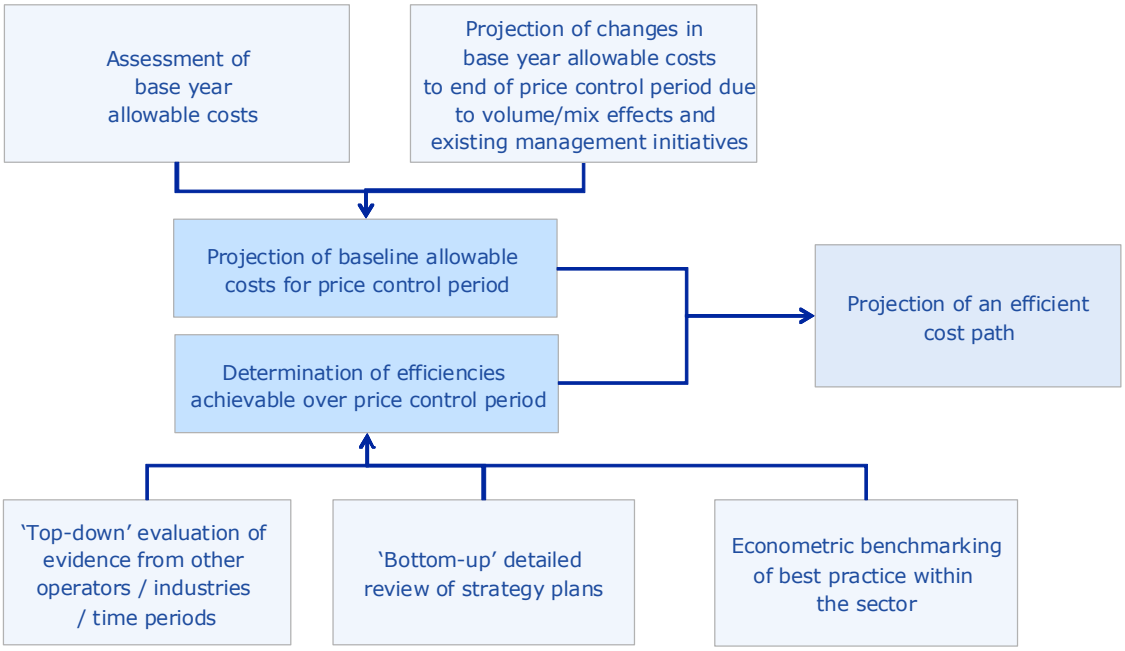
harmonised consumer price index (HICP) – which has been granted by certain GB regulators and highlighted by BGN as an issue faced by its networks business in PC3.

Our view is that RPE allowances, set pre financial crisis, have with the benefit of hindsight been very generous to the GB network operators. As part of our bottom-up assessment for PC3, we have also not seen evidence to support a positive RPE allowance for BGN's gas networks business, specifically as regards changes in general and specialised labour inflation over time relative to the general Irish economy (as captured by Irish HICP or the national Consumer Price Index (CPI)).

Therefore, on the basis of the findings of our bottom-up and benchmarking assessment, we have concluded a separate RPE allowance *should not* be applied to BGN's opex in PC3. This means our proposed opex allowances, in our view, account for RPEs in PC3 and reflect an efficient and achievable real cost path for the business over the control period.

Figure 1.1 summarises our approach. While the diagram focuses on opex, our assessment of capex can be considered part of the 'bottom-up' review of BGN's PC3 strategy plan and the projection of baseline allowable costs for the price control period.

Figure 1.1: Setting an efficient cost path



1.3. Objectives

The objectives of this report are to:

- summarise the process that the consortium has followed to assess the efficiency of BGN's opex and capex;
- highlight the context to the revenue control review including the high level outputs BGN proposes to deliver through its transmission business in PC3;

- provide a brief review of the PC2 revenue control structure, its incentive properties and BGN's performance in the PC2 period;
- review of the explicit and implicit outputs and objectives that CER might wish to establish for BGN in PC3; and
- to provide a view of the consortium's proposed adjustments to BGN's proposed transmission revenue requirement (opex and capex allowances).

We also summarise the findings from our own and BGN's transmission benchmarking analysis and our proposals for the incentive regime in PC3.

1.4. Review process followed

To determine an appropriate regulatory regime and efficient opex and capex spend for BGN's distribution business, the consortium has reviewed detailed submissions from BGN about its plans for its distribution business in PC3 and its associated revenue requirements. The key stages in the review process are summarised in Table 1.1.

Table 1.1: Review process milestones

Milestone	Timing
Issuance of information request to BGN	15th August 2011
Clarification questions and note on information request	25th August 2011
BGN response to historical information request	28th October 2011
BGN presentations on historic information	15th – 16th October 2011
BGN response to forecast information request	7th December 2011
BGN presentations on forecast information	13th – 14th December 2011
Consortium review of BGN submission	December 2011 – January 2012
Consortium submission of reports to CER	2nd February 2012
CER submission of consortium reports to BGN	3rd March 2012
Consortium presentation to BGN	8th March 2012
BGN response paper	15th March 2012
BGN presentations on response paper	16th March 2012
Submission of final consortium reports	4th May 2012

Source: Consortium

The first stage in the process was the issuance of an information request to BGN on the performance of its distribution business in Price Control period 2 (PC2) and the 2006/07 gas year[2] and the company's forecast costs and outputs in PC3. Clarifications were then provided to queries raised by BGN on the original information request.

[2] The final year of Price Control period 1 (PC1).

The consortium then reviewed the information submitted by BGN in October (historic information) and December (forecast information) and held a series of meetings with the company and the CER in the week following the information submission. A series of supplementary questions were also asked by the consortium and responded to by BGN.

The consortium then submitted draft reports to the CER with our initial conclusions and recommended opex and capex spend. The reports and our proposals were based on BGN's response to the original information request and clarification questions raised by the consortium. The reports were discussed with the CER before being submitted to BGN.

A series of meetings were then held between the consortium, BGN and the CER to discuss the consortium's draft reports and additional information provided by BGN as part of their response paper submitted on the 15th March.

Having reviewed the BGN response paper, the consortium developed an updated view of our recommended opex and capex allowances. This updated and recommended view on an efficient cost path for BGN's distribution business in PC3 is subject of this report.

1.5. Document structure

The rest of this document is structured as follows:

- Section 2 provides background information and context;
- Section 3 summarises our review of transmission incentives and uncertainty mechanisms;
- Section 4 reviews outturn transmission opex in PC2;
- Section 5 summarises our proposals for transmission opex in PC3;
- Section 6 reviews outturn transmission capex in PC2;
- Section 7 summarises our proposals for transmission capex in PC3;
- Section 8 reviews ITO setup costs;
- Section 9 summarises our findings from the benchmarking analysis;
- Section 10 concludes with our proposed transmission allowances.

2. BACKGROUND INFORMATION AND CONTEXT

2.1. Overview

This section reviews the structure of the price control in PC2 and summarises the background and context leading into PC3. This includes BGN's high level outputs which it is proposing to deliver through its transmission business in PC3.

2.2. Price Control 2

Table 2.1 provides a summary of the regulatory incentive regime put in place by the Commission for the PC2 period for transmission.

Table 2.1: Key aspects of BGN distribution price control and incentive regime

Element	Transmission
Form of control	Revenue-cap
Length of control	5-years
Headline control	CPI-0%
Cap/Com split	90:10
Pass-through	Some 50:50 sharing
Incentives	Rolling capex Rates CO_2
Additional Opex efficiency	0%
Other elements	Guidance for PC2 on: - Opex clawback; - Capex clawback; - Incentive retention; and - Reopeners and triggers

Source: CEPA

2.2.1. Regulatory outputs

For transmission, the CER did not specifically propose "outputs" but highlighted a number of benefits for the transmission customer over the life of the price control period. These included facilitating the connection of large I/C loads, development of new products (including short term products and development of the interconnector storage product), facilitating ongoing cost efficiencies and continuing to meet pipeline safety standards and address risks associated with security of supply.

2.2.2. Regulatory incentives

In PC2 the CER sought through its price control to provide strong regulatory incentives for BGN to make efficiency savings in the day to day operation of its networks business, and through efficient and timely investment in the network infrastructure and systems. This was primarily achieved through the treatment of expenditure in the price control. However, in addition to creating incentives by the treatment of expenditure in the price control, CER also put in place specific performance and behavioural incentives for the network businesses outputs, for example, incentives for management of CO_2 volumes.

Operating expenditure

CER set a revenue cap for BGN's transmission activities in PC2. As was noted by the CER in the PC2 decision paper, in theory an overall revenue cap provided a strong regulatory incentive for BGN to make efficiencies as it retains the savings for the remaining period of the price control.

CER also increased the length of the price control from a four year control in PC1 to a five year control in PC2. This increased the incentive strength (compared to PC1) by providing more certainty to BGN and increasing the retention period for any opex efficiency savings the company was able to make over the PC2 period.

The overall revenue cap was supplemented by regulatory guidance provided by CER for the control period. This sought to clarify incentive arrangements for opex. CER proposed for overall operating costs, i.e. other than for pass-through items (see below), it was for BGN to manage actual outturns within its revenue allowance. CER proposed it would not in general expect to clawback overall or individual items for which there was under spends of opex.

However, neither did CER expect to allow BGN to recover higher costs at an overall or individual level. Consistent with the revenue cap for opex allowances, BGN was expected to manage overspends within the overall revenue allowance. Overall, this provided a strong incentive to control costs and make efficiency savings.

Pass-through incentives

While the majority of BGN's operating costs were include in the revenue cap, different incentive arrangements were created around a small number of pass-through items. Following the structure of the price control in PC2, these cost items were treated as pass-through because they were considered largely outside the control of BGN.

For these costs, rather than a fixed ex ante budget set for the start of PC2, a forecast budget was established and then updated over the course of the control period, through the CER's annual tariff determinations and K-factor adjustments. In the case of transmission, this included expenditure related to business rates, the CER levy and management of CO_2 volumes from compressor stations.

Capital expenditure

Under PC2 regulatory arrangements, BGN is rewarded for making savings against its capex budgets through the Regulatory Asset Base (RAB). Prices were set at the start of PC2 on the basis of an opening RAB value, together with a stream of projected capex figures (set out in the PC2 decision) for projects approved by the CER.

In general terms, where BGN was able to achieve a saving compared to its projected investment PC2 allowance in a given year, then it would be allowed to earn the rate of return plus a depreciation payment on the expenditure saved. It would retain this benefit for five years, at which point the notional RAB and depreciation payments are recalculated on the basis of actual investments.

The capex incentive is thus a rolling incentive mechanism that allows BGN to retain the savings from cost savings for the same length of time (i.e. five years) regardless of when the savings on investment were made in the price control. This arrangement was put in place to avoid adverse incentive effects that are created if the networks business was only able to retain the efficiency savings up to the point of the next price control review.

As with operational costs, CER supplemented this regime with specific guidance on how it expected to approach assessing under and over spends of capex. This was to provide clarity to BGN on how CER expected to approach these issues in PC3 both for efficiency savings (i.e. where projects went ahead as planned) but also where specific projects were not carried out or deferred. In providing this guidance, CER noted that its objective was to improve certainty for BGN and thereby improve the company's incentives to make efficient savings and investment decisions.[3]

2.3. Price Control 3

BGN's business plan (PC3 submission) proposes a series of outputs which it proposes to deliver in PC3 and the revenue allowance is requires for those outputs. The associated capex and opex requirements are discussed in the later sections of this paper, while the context for BGN's proposed output areas is discussed in the subsections below.

2.3.1. Proposed outputs

BGN has proposed seven outputs for PC3:

- promoting competitiveness – operating the networks efficiently and effectively;
- maintaining a strong customer focus;
- delivering a safe and secure network;
- promoting innovation and sustainability;

[3] The regulatory principles and objectives of the PC2 guidance for opex and capex are discussed further as part of our outputs and incentives report - CEPA, GL Noble Denton and PKF (2012): 'Gas transmission and distribution revenue control: outputs, incentives and uncertainty mechanisms'

- successfully delivering the European Third Directive unbundling and market arrangements;
- financing its activities efficiently; and
- embedding the Independent Transmission Operator (ITO) and High Performance Utility Model (HPUM) structure.

The context to these outputs is discussed in the subsections below.

Organisational change

BGN highlights in its BPQ response that its networks business underwent major organisational change in PC2. This was focused on: "*significantly enhancing the work delivery and asset management capabilities within BGN* [following implementation of the Networks Transformation Programme (NTP)]. *BGN now operates a high performance utility model (HPUM), which places asset management at its centre*."[4]

BGN also established a separate ITO structure, systems and processes in PC3 to ensure it fully complies with the requirements of the European Third Gas Directive. This will mean BGN will be legally separated from its parent company (BGÉ) which provides retail services to the Irish gas market, amongst other business activities.

Amongst BGN's proposed outputs for the PC3 period, is the embedding of this new organisational structure. Through the HPUM – including the outsourced contract model BGN has operated in the past – the company expects to operate efficiently in the PC3 period and to optimise the HPUM model to the benefit of "*the Network, Customers and Regulatory Authorities, by ensuring management of the network is proactive, timely and efficient*."[5]

Changes in gas markets

Changes *within* BGN's networks business have also taken place during a period of major change in the Irish gas market.

The Irish gas market is now open to competition and the entrance of Airtricity and Electric Ireland has resulted in a major boost to gas domestic retail competition.

As BGN highlight in its BPQ response, there are also potential changes to the gas market arrangements in PC3, emerging from the requirements of the European Third Gas Directive (development of European gas codes) and joint work between the CER and NIAUR in shaping the Common Arrangements for Gas (CAG) framework.

[4] BGN (2011): 'PC3 Executive Summary – PR068'
[5] Ibid.

Sustainability, competitiveness and security of supply

The Irish Government has put in place a strategic energy framework for Ireland that states amongst its objectives, sustainability, competitiveness and security of energy supply.[6]

BGN's PC3 business plan suggests certain reinforcement activities on the transmission network are required to contribute to the security of supply objective. It also highlights promotion of safety as a "leading company value".

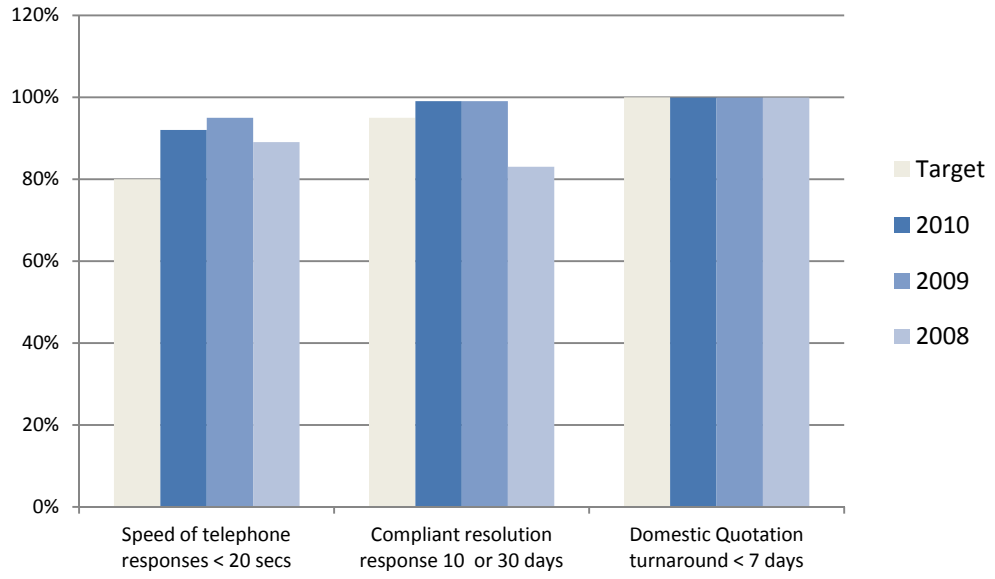
The Corrib gas field is also expected to start production in PC3 (2014/15). There are changes in the electricity sector that will also impact on the operation of BGN's gas networks, for example the increasing deployment of wind generation in the SEM and the East-West Interconnector.

BGN has also proposed an innovation funding scheme for PC3, which would be expected to contribute to the environmental targets and sustainability of the Irish economy. BGN has proposed that a Gas Innovation Group be established to govern this funding mechanism.

Customer focus

BGN also highlights its intention to maintain a strong focus on customers in PC3. This includes an objective to outperform its customer charter targets and achievement of Customer Service Key Performance Indicators (KPIs). Figure 2.1 highlights the company's achievements in this area.

Figure 2.1: BGN customer performance standards in PC2



Source: BGN

[6] DCNER (2006): 'Delivering a sustainable energy future for Ireland'

BGN also proposes to help customers in financial difficulties through its customer engagement programme and prepayment meters. Finally, BGN plan to grow the network through significantly increasing its "sales effort and market development activities over PC3 in order to increase our customer base."

Uncertainty mechanisms

There is uncertainty around the timing of certain impacts on BGN's transmission network business and what BGN believes it may need to deliver in PC3. For example, the timing of Corrib gas field starting production and regulatory change related to the Third Directive and the Common Arrangements for Gas (CAG).

For these items, BGN is seeking uncertainty mechanisms, including the capacity for price control reopeners or more specific investment triggers in certain cases. The case for investment triggers is based on the precedent of their use in PC2 and BGN's view that there is uncertainty of the timing of certain events and investments.

There are also a number of activities and costs that might be considered outside BGN's control. These are termed pass-through items, as aspects of the price and/or volume of work is considered not to be controllable by BGN. In its business plan, BGN has retained items that were deemed by the CER to be pass-through in PC2 as pass-through in PC3.

Summary

Given this context, BGN has linked its future capex and opex requirements in PC3 to high-level outputs that support the delivery of identified objectives or programmes within these broad output areas. The key points to note (in our view) are that BGN has proposed to implement a HPUM within an ITO structure in PC3 that focuses on asset management *and* customers / users of the gas networks in Ireland.

2.4. Consortium views

There have been two previous multi-year determinations of revenue requirement for the Irish gas transmission and distribution networks, with the current one (PC2) operating until 2011/12. The gas industry in Ireland is one where the bulk of the infrastructure is now in place and while this does not mean that there will be no proposed investment, what it does mean is that the investment plans for PC3 need careful analysis to ensure that they are appropriate. An ITO structure is also now in place while previously BGN was more closely integrated with BGE.

The activities the CER might expect BGN to deliver for customers in PC3, and the regulatory incentives and price control arrangements used support delivery, may as a result need to change to accommodate these changes. For example, with the bulk of infrastructure in place, CER might expect BGN to maintain and develop an economic and efficient network through greater consideration of the alternative solutions to investment (through system operation measures) and the impacts and trade-offs of not undertaking investment.

This raises issues such as the role of IT in network operation and management, and the types of expenditure and incentives that might be needed to support an asset management capability. GDNs in GB underwent similar network IT and investment projects to BGN following the GDN sales in 2005.[7] As well as by network sales, this was driven by the need for an asset management capability for a mature network asset base, a capability BGN highlight as important for its networks business in the future.

Many of the high-level outputs BGN has proposed in its business plan for the PC3 period are, in our view, wholly appropriate for a gas ITO business seeking to operate as a HPUM similar to the GDNs. In particular, we note:

- Given the organisational change and the investment BGN has made in its systems and processes in PC2 to enhance work delivery and asset management capability, BGN's commitment to ongoing efficiency across its network business.
- We are supportive in principle of an innovation funding scheme for the Irish gas industry provided it is focused on innovation, for example research and development, involves a range of industry stakeholders and demonstrates value for money for the consumer.
- We are also supportive of BGN's focus on asset management capability given the rollout of the gas network in Ireland and the HPUM structure. It continues to be important for BGN to deliver a safe and secure gas network for Ireland.

However, as illustrated by the case of the GB GDNs, CER needs to apply careful thought to how BGN's changing network activities and outputs are captured by the service performance and behavioural incentives it creates for the networks business. This includes the more general incentives created through treatment of different types of expenditure in PC3.

As we explore in our published report on incentives, given the HPUM structure has only recently been implemented, it would seem sensible to largely retain the PC2 incentive arrangements (where elements remain appropriate). This can allow management processes to bed down within BGN's business and more data to be collected on actual performance of the HPUM.

However, looking forward to PC4, the CER may wish to consider how the incentive regime created through the price control arrangements could be linked much more closely to the objectives and outputs of BGN's HPUM. The experience of the GDNs under Regulatory Incentives Innovation and Outputs (RIIO) GD1[8] may provide useful lessons in this regard.

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[7] See for example:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=19&refer=Networks/GasDistr/GDPCR7-13

[8] RIIO-GD1 will be the first gas distribution price control review to reflect the new regulatory framework resulting from Ofgem's RPI-X@20 review.

3. INCENTIVES AND UNCERTAINTY MECHANISMS

3.1. Overview

In PC2, the CER sought through its price control to provide strong regulatory incentives for BGN to make efficiency savings in the day to day operation of its networks business, and through efficient and timely investment in the network infrastructure and systems. Therefore, incentive based regulation formed the core of its PC2 decision and regime. In the longer term this was considered to be the way in which customers would obtain the greatest benefit through lower prices, as BGN improved its efficiency.

The CER also noted the importance of ensuring that BGN was accountable for spending the revenue allowed under the PC2 determination appropriately, and in particular, to deliver the outputs that were expected to be delivered with the revenue. Therefore, in both its transmission and distribution decisions, CER specifically set out the outputs and outcomes that BGN were expected to deliver with its allowed revenue, and the incentive arrangements that applied to the costs related to the delivery of those outputs. Those outputs were a combination of specific observable outputs and standards to be achieved by BGN.

In our separate report on incentives, we have reviewed the performance of the outputs and incentives regime in PC2, and the approach adopted by CER for managing uncertainty, and what lessons might be learned for PC3 from the PC2 experience. We have then gone on to assess the options for incentives and performance in relation to transmission for PC3. This has involved a review of explicit and implicit outputs and objectives that CER might wish to establish for BGN in PC3 and how these could be linked to incentive regimes. This section summarises the conclusions from our analysis and the specific proposals we have made.

3.2. Review of incentives

We have approached our review of the options for possible incentive regimes and uncertainty mechanisms by considering the following:

- principles of regulatory incentive regimes;
- current framework;
- BGN's proposals for PC3 (where they exist);
- performance of PC2 arrangements;
- regulatory precedent, specifically Ofgem and CER; and
- possible options for PC3.

With our approach to incentives including an assessment of the current framework and guidance for PC2 – in particular, incentives created through the treatment of expenditure in the price control – there is a link to other analysis prepared by the consortium on BGN's outturn expenditure and

performance in PC2. In particular, issues around the guidance CER provided at the previous price review on efficient management of opex and capex. We briefly summarise our conclusions on the opex and capex incentives (given these are the most important aspect of the incentive regime in expenditure terms) in the sections below.

3.3. Opex incentives

We continue to believe that a revenue cap provides strong regulatory incentives for BGN to make efficiency savings. Therefore, in line with CER's PC3 position paper[9], we propose the CER retain a revenue cap for the vast majority of BGN's controllable transmission and distribution opex. We note the major restructuring of BGN's business in PC2, notably the organisational change and IT investment from the NTP.

BGN's own BPQ submission highlights a key objective of the programme was to drive efficiencies and business benefits for its networks business. These benefits should be clearly reflected in the *baseline allowance* set for both transmission and distribution in PC3. The objective of the opex incentive regime should be to incentivise BGN to control costs within its allowance and to realise *unanticipated* savings in PC3 that can be shared with consumers in future periods.

Given BGN's outturn in PC2 relative to the incentive regime and allowances set by CER, careful thought must be given to setting a baseline level of costs moving forward into PC3, given the proposed opex incentive regime. Benchmarking of BGN relative to similar gas ITOs has an important role to play in setting that baseline.

3.4. Capex incentives

Strong capex incentives are important for capital intensive businesses such as BGN. We therefore propose that CER seek to retain the rolling capex incentive mechanism for both transmission and distribution revenue controls in PC3.

While certain aspects of the regulatory guidance on capex incentives have worked better than others, partly we believe this is a result of the operating environment that we have reviewed BGN's outturn capex against.

In our view, the regulatory guidance and incentives for capex have gone part of the way to meeting their stated objectives in PC2 and should, therefore, be retained in PC3. We believe this is particularly important in the context of the significant changes to BGN's networks business since the PC2 review, in particular, the move to a HPUM and asset management capability. Strong capex incentives need to be maintained on BGN to:

i. find efficiency savings when capital projects do go ahead (for example, large and uncertain capital projects); and

[9] CER/11/070

ii. seek long term solutions which may or may not involve capex to deliver the desired outcomes by consumers and the CER.

However, CER may wish to revisit aspects of the capex incentives and guidance (for transmission and distribution) to provide greater clarity particularly around the criteria and boundaries of different definitions of expenditure. For example:

- whether overspends are managed and assessed at a project (transmission) or category level (distribution) or managed as a large 'bucket' in PC3;
- ensuring the regulatory incentive arrangements provide appropriate and balanced incentives for capex and opex; and
- a clearer definition of the boundaries between variance categories such as scope and true efficiency savings.

3.5. Innovation

In principle, the consortium is supportive of a form of innovation funding scheme for the Irish gas industry. Total innovation funding requested by BGN for PC3 (for transmission and distribution) was c.€26m including €17m of opex and €9m of capex. BGN proposes to seek on-going innovation funding of at least 0.5 per cent of revenue per annum, but typically 1 per cent in the early years of innovation. BGN have proposed a wide range of innovation projects in their submission to support this funding request. We do not propose to comment on each individual project however some examples are provided in Table 3.1 below.

Table 3.1: BGN proposals for innovation funding

Project	Comment
Natural Gas in Transport – Compressed Natural Gas	This is intended to facilitate the use of CNG in Ireland as a transport fuel following introductions across Europe and the USA. As part of this process, BGN state the supply chain will need to be developed, awareness created and cross industry co-operation encouraged.
Bio-methane injection into Gas Grid	The aim here is to initiate supply chain development of an emerging bio-methane production market and find an efficient cost model. BGN has requested both opex and capex to support bio-methane injection projects in PC3.
Network Extension/ Fuel poverty	The idea behind this plan is to allow those in fuel poverty to convert to natural gas without the up-front costs. They are required to be within 15m of the existing distribution network.
Asset Management Research and Development	Materials Design & Innovation is a large part of Asset Management. The proposed opex allowance is based on a number of projects. The benefits of these projects would be in increased safety, decreased environmental impact and greater efficiency.

Source: BGN and CEPA

Having reviewed BGN's proposals, and precedent in other sectors, we conclude that CER *should* seek to implement a form of innovation funding in PC3. However, the allowances proposed by BGN are significant and so the scope of funding and proposed projects should be reviewed and prioritised by CER. Detailed governance arrangements should be developed with industry stakeholders for approval by CER, including project approval, monitoring and evaluation.

While BGN's innovation submission begins to outline how some of these governance issues for an innovation fund might be addressed, key issues such as incentives around the revenue allowance, the focus and definition of innovation projects and the role of external stakeholders in the process in particular require further consultation.

We therefore propose 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 also be developed and approved by the CER.

We propose CER seek to provide an innovation allowance within the price control revenue cap of €8m (80:20 split for T&D) subject to the specific governance controls and criteria for the release of funding set out above. Given our views on the focus of innovation funding and to avoid complications of including small capital projects in the RAB, we recommend that the €8m be funded purely as opex.

3.6. Uncertainty mechanisms

There is timing and investment uncertainty related to a number of key transmission infrastructure projects in PC3 including the connection of Shannon LNG and the start date of Corrib.

From our discussions with CER and BGN, we understand there is now increasing *certainty* of when Corrib is likely to start production. From the perspective of setting CO_2 allowances (which is partly why a negative investment trigger was included in the PC2 decision), we *would not* propose CER implement a negative trigger in PC3 for Corrib.

If there is a change in the CO_2 volumes from a year or more delay in Corrib production, we believe in this case, the issue is better addressed through BGN logging-up the variances in costs. CER may still wish to consider a trigger for tariff purposes. As this is outside our terms of reference, we have not considered the issue further.

Since there is continuing uncertainty with regard to the Shannon LNG terminal we propose the CER adopt the same approach as for PC2 – i.e. a positive trigger included in the transmission price control whereby revenues will be increased if the project is undertaken during the control period.

We note the requirement and timing for twinning of the South West Scotland Onshore System (SWSOS) in the PC3 period is also a source of uncertainty in PC3.

While we do not believe that there is a need to construct the pipeline in the short term, we do believe remedial measures should be taken by the CER and BGN to overcome potential issues at Moffat ahead of Corrib starting production. While questions remain of the practicality and timing of these alternative measures, this adds uncertainty to the control period.

We therefore propose the CER exclude BGN's proposed SWSOS reinforcement costs from the revenue allowances (see Section 7) but include a positive trigger in the determination so that should the project need to go ahead, BGN would be able to recover those costs.

BGN has proposed Inch Refurbishment spend of €2.89m associated with refurbishment of Midleton compressor station to cater for reduced flows through the Inch Entry Point as a result of the decommissioning of the PSE Kinsale Gas Storage Facility post-2013/14. Our view is that the €2.89m forecast should be allowed at this stage but captured by a negative investment trigger. This will mean that were a decision taken not to de-commission the Kinsale Gas Storage Facility then revenues would be reduced to reflect the impact of this.

3.7. Summary of proposals

Our proposals for transmission outputs, incentives and uncertainty mechanisms (including key aspects of the regime discussed above) are summarised in the table below.

Table 3.2: Outputs, incentives and uncertainty mechanisms proposals

Element	Proposal
Regulatory Outputs	Regulatory outputs proposed by BGN appear broadly appropriate for a gas ITO. Clearer definition of specific deliverables may be required for final PC3 decision.
Opex incentive	Seek no clawback on opex Retain revenue cap Careful assessment of base year costs
Capex incentive	Seek some clawback on items of PC2 efficient deferral which does not meet proposed criteria (see Section 6) Retain capex rolling incentive Review drafting of guidance on underspends and overspends
Pass-through items	Retain rates and CO_2 emissions as incentivised pass-through Retain CER Levy as 100% pass-through
Innovation incentives	Provide for an innovation funding scheme – open to all stakeholders with governance arrangements to be approved by CER upfront Allow €8m as opex for innovation funding (€6.4m for transmission and €1.6m for distribution) Approval of projects before initiation by industry stakeholder body &/ or CER
Other sources of uncertainty	Positive trigger for Shannon LNG project Positive trigger for twinning of SWSOS Negative trigger for Inch refurbishment spend

Source: CEPA

4. OUTTURN OPEX IN PC2

4.1. Overview

This section examines BGN's historical operating expenditure. The historical review of opex is used to derive normalised costs that form the basis for our proposed PC3 opex allowances.

The objective has been to develop a base year of normalised transmission opex costs that represents the core historic "business as usual" opex expenditure and which can then be revised to reflect additional items of core opex forecast to be incurred in future years. Our normalised costs have been 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 consideration of the impact of allocation and related party profit issues.

The base year of normalised transmission opex costs, has then been used to project forecast opex costs into the next price control period (see Section 5).

4.2. Review of outturn

The following table summarises the main headings of opex for the Transmission business in comparison with the PC2 allowance, and shows the variance against the allowance.

Table 4.1 Transmission opex for PC2 by year and in total compared with the total PC2 allowance €k

TBU Opex analysis - Historic								
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
Direct								
INCH	908	820	1,093	879	841	**4,541**	**6,109**	**1,568**
Interconnector Opex	6,890	9,883	7,924	6,841	11,636	**43,174**	**51,965**	**8,791**
Less PTL Contributions	- 1,095	- 1,464	- 1,408	- 1,039	- 1,351	**-6,357**	**-7,090**	**-733**
Onshore	11,500	12,387	12,151	16,572	15,544	**68,154**	**68,703**	**549**
Direct sub-total	**18,203**	**21,626**	**19,760**	**23,253**	**26,671**	**109,512**	**119,687**	**10,175**
Miscellanous Adjustments	1,874	346	-988	-599	2,696	**3,329**	**0**	**-3,329**
Business Support Services	11,865	14,709	14,146	16,752	18,994	**76,465**	**70,590**	**- 5,875**
ISO	2,025	2,482	2,610	2,312	2,756	**12,185**	**12,802**	**617**
Pass through	12,292	12,016	12,464	12,877	12,984	**62,633**	**87,644**	**25,011**
Grand Total	**46,259**	**51,179**	**47,992**	**54,595**	**64,101**	**264,125**	**290,723**	**26,598**

Source BGN's PC2 BPQ submissions

BGN has under-spent overall in PC2 by €26.595 million. The key features of the under-spend are:

- under-spend on Direct opex of €10.173 million;
- under-spend on pass through costs, [redacted];
- offset by an overspend on Business Support Services of €5.875 million and miscellaneous adjustments of €3.329 million.

The table below summarises the Direct opex under-spend

Table 4.2 Transmission Direct opex for PC2 by year and in total compared with the total PC2 allowance €k

TBU Opex analysis - Historic Variance Analysis								
2010/11 Monies €k	2007/08 Variance	2008/09 Variance	2009/10 Variance	2010/11 Variance	2011/12 Variance	PC2 Total	PC2 Allowance	PC2 Variance
Direct OPEX								
INCH	- 163	- 363	- 88	- 528	- 424	4,541	6,109	**1,568**
Interconnector Opex	-4,590	-1,227	-2,075	-2,576	1,677	43,174	51,964	**8,790**
Less PTL Contributions	- 479	115	315	- 432	- 252	-6,357	-7,090	**-733**
Onshore	-1,949	-3,423	-4,185	278	1,876	68,155	68,702	**547**
Direct sub-total	**-7,181**	**-4,898**	**-6,033**	**-3,258**	**2,877**	**109,513**	**119,685**	**10,172**

Source BGN's PC2 BPQ submissions

The principal reasons for the Direct opex under-spend relate to:

- completion of the INCH Cork uprating project resulted in a lower maintenance and operating cost of the Midleton Compressor Station and also a reduction in running hours;
- BGN reaching agreements with the relevant safety authorities in reducing subsea pipeline inspections resulting in a PC2 saving of €5.818 million;
- overall PC2 savings in SCADA system costs €1.530 million which BGN state relate to efficiencies; and
- cost savings of €0.976 million relating to onshore pipeline maintenance and operations.

[redacted]

Our BPQ included a rolling opex reconciliation intended to show the quantum together with an explanation of the significant changes in opex from one year to the next. BGN provided the information in summary form only by tariff category with no supporting explanation other than the full written submission. We asked BGN to show the required analysis and, in particular, to show the impact each year of the implementation of the HPUM that resulted from the NTP in the early part of PC2, and the changes to establish BGN as an ITO in the latter part of PC2.

These were major organisational changes that have had a material impact on operating costs. BGN's operating costs are presented after applying a complex multi-stage allocation process that has changed with the organisational changes. Additional supporting narrative for the final two years of PC2 has been provided but not for the first three years. Some further high level descriptions relating

to the impact of the NTP and the ITO each year has been provided at BGN level and we have utilised this information in as reasonable a manner as is possible.

BGN has stated that as a result of the NTP and ITO programmes that it now has the tools in place to realise operational savings across the organisation. However while some savings were identified by BGN in its NTP benefits realisation review, the ITO changes were made on a "lift and shift" basis to enable BGN to operate independently of its parent (see Section 8).

The project has included the comprehensive documenting of every current procedure by external consultants and the associated training of staff. Due to the lack of available time no process improvement or reengineering has been undertaken. Furthermore BGN has not provided sufficient evidence that the savings that have been claimed from these major investments are fully reflected in their PC3 submission.

Our conclusion is that BGN has not been able to justify the substantial increase in operating costs resulting from the two major programmes undertaken in PC2. There is also an absence of evidence of the savings that these initiatives will achieve in PC3. We have not accepted the increased level of operating expenditure presented by BGN. We have based our projections of the normalised annual cost on the information available and broad adjustments to reflect the lack of compelling evidence to support the increases in costs going forward.

4.3. Cost drivers

BGN's Executive Summary for PC2 states that the approach to Asset Management and the adoption of condition based maintenance following the NTP has resulted in the identification of a number of unforeseen maintenance requirements towards the end of PC2.. The requirements of the EU Third Energy Directive and the steps taken to establish BGN as an ITO have also increased operating expenses significantly toward the end of the price control.

The other cost driver has been the downturn in the economy which has resulted in reduced investment and the under-spend against the Capex allowance in PC2.

4.4. Network Transformation Programme

There have been significant organisational changes that have impacted the cost base and the allocation of costs in PC2. The NTP in the first half of PC2 resulted in the adoption of a HPUM and a significant investment in processes and systems. The business was restructured to facilitate Network Asset Management and Supply Chain Management, both expected to result in significant savings over time. BGN claimed that the key benefits of the programme were:

- Centralisation and standardisation of work progression with increased automation;
- Increased productivity in the field through improved scheduling and the use of mobile devices; and
- Increased responsiveness to customers.

BGN has stated that the bulk of the benefits have impacted the supply chain and in particular capital expenditure. The following table summarises the targeted savings (by calendar year as submitted – we have summed the approximate PC2 and PC3 gas year totals).

Table 4.3 NTP targeted savings by year and in total across BGN T&D €m (2010/11 prices)

[redacted]

Source Derived from BGN's PR029 NTP submissions

While the additional ITO costs in the latter part of PC2 masks the impact, the ITO costs are largely back-office and we would expect to see the impact of the investment in PC3. We have seen little evidence of these savings. BGN has been asked to demonstrate that these savings have been realised but has not provided this information. We have concluded that any savings in opex in PC2 appear to have been more than offset by increased operating staff costs resulting from the HPUM restructure and from increased charges associated with adopting an asset based maintenance programme.

4.5. Independent Transmission Operator

The cost of establishing the ITO following Third Directive requirements is discussed in Section 8. There we also comment on BGN's claim for an additional allowance of €10m for ITO opex costs that arose in PC2.[10]

4.6. Human resources

[redacted]

[10] Opex not anticipated at the time the PC2 allowances were set.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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[redacted]

4.7. Cost allocation bases

The allocation bases that were applied in PC1 continued in the early part of PC2. With the adoption of an asset-based HPUM, a new cost centre structure was applied and the structure of Networks shared costs and the allocations methodology were revised from the beginning of 2010. As a result of these changes, a revised tariff structure has been proposed by BGN. For ease of comparison BGN has presented the allowances and actuals consistently across the five years of PC2 covering the shared services portion of the business as part of what it has called Network Business Support Services.

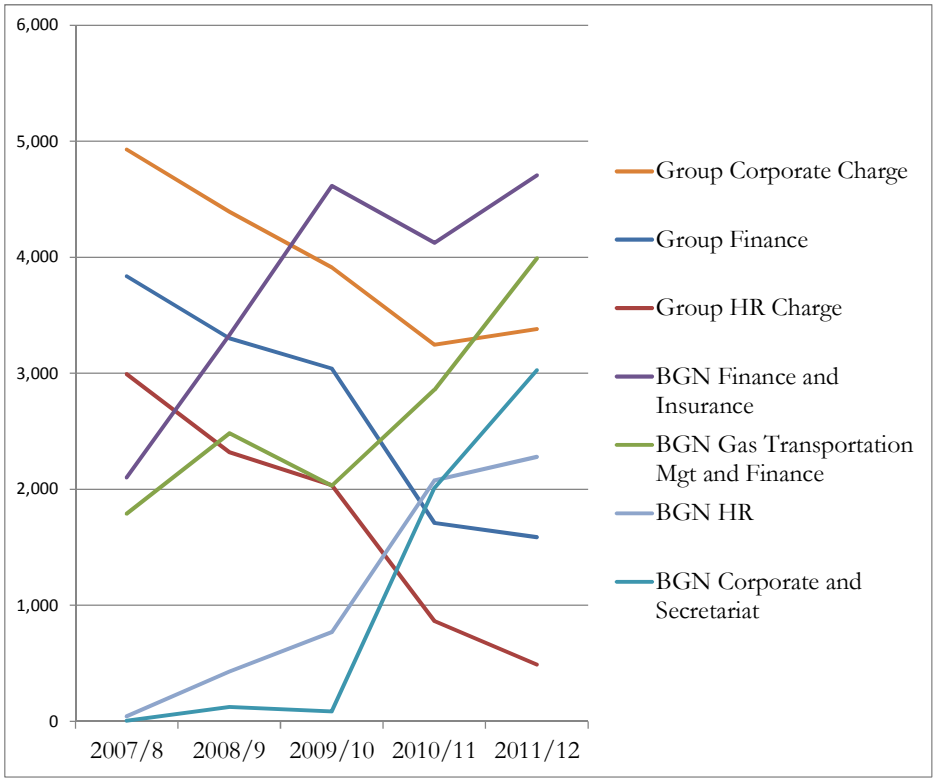
4.8. Direct opex

BGN reports their Transmission Direct opex costs under the following key headings: (i) Inch; (ii) Interconnector opex; and (iii) Onshore. The total actual opex for the PC2 period was €109.5m versus a PC2 tariff allowance of €119.6m, representing an under-spend of €10.1m (or 8.5%).

4.9. Business Support Services including IT and Telecoms and staff cost analysis

In previous years Transportation and Shared Services have been allocated to the Distribution business. As a result of the organisational changes in PC2, BGN has referred to these services as Business Support Services which, with the establishment of the ITO, have become an integral part of BGN but still need to be apportioned over the Transmission, Distribution and unregulated businesses within BGN. The following figure illustrates the reducing dependence on Group services resulting from BGN taking steps to become an ITO.

Figure 4.1 Comparison of actual annual Finance and Corporate costs disaggregating the group allocation from the BGN direct element before allocation (actual in nominal prices including 2011/12 in 2010/11 prices) in €000s



Source: Derived from supplementary BPQ information

The Group Shared Services structure represents a headcount of 40 of which 50.4% is allocated to BGN. The further analysis provided by BGN indicates that the Group allocation has fallen from €14.4 million in 2007/8 to €5.4 million in 2011/12. However in aggregate the Finance and Corporate costs have increased by a third over PC2 and the Group allocation represents nearly 3% of BGN's turnover, a percentage that is significantly higher than other network operators in the gas networks sector. We therefore propose a normalised annual cost reduction adjustment of 50% of the allocation.

We note that the ITO project has been carried out as a "lift and shift" project which means that a significant amount of time has been devoted to documenting existing processes without any re-engineering. BGN has stated that the systems are in place to realise savings from process re-engineering in the future. We feel that BGN has missed the opportunity to take a more pragmatic approach that focuses on key areas allowing time for process improvement and transformation while adopting a minimalist approach to those less critical areas. For this reason we propose a normalised annual cost adjustment of €500k representing the savings that should have been achieved through a project of the scale of the ITO setup (known internally within BGN as Project 3).

The following table shows the change in Corporate and Secretariat costs.

Table 4.6 Change in Corporate and Secretariat costs from2009/10 to 2011/12 in 2010/11 prices €ks

2010/11 Monies €k	2009/10 Actual	HICP adjustment to 2010/11 prices	2011/12 forecast	Change 2009/10 to 2011/12
Corporate & Secretariat	86	87	3,025	2,939
Group Corporate & Secretariat	3,912	3,959	3,380	- 532
Total	**3,998**	**4,046**	**6,405**	**2,407**

Source: Consortium – derived from BGN BPQ response

The headcount within Corporate and Secretariat is 14 at the end of 2011. BGN explain that the significant increase reflects the cost of operating an ITO board and a fully functioning secretariat department. We have made an adjustment of €200k for the missed opportunity for process rationalisation and a further €500k because we believe the full increase is not justified given the headcount involved. However we have made some allowance for the additional cost of running an ITO.

4.10. IT and Telecoms Operating Costs

BGN spent €40.1m against an allowance of €34.7m in the PC2 period as follows.

From information provided by HR, we understand that there were 16 additional posts in this area following the ITO changes. We understand that the sum of the independent IT functions will be higher than the shared resource and we further understand that the user base has increased and NTP running costs and software licence costs have risen (BGN estimates the additional NTP costs to be €2m). However we have not accepted the scale of the increase in IT costs and make a number of normalisation adjustments below.

Based on our analysis the following are adjustments to the 2011/12 forecast:

- Given the scale of major programme activity in PC2 we would expect a significantly reduced level in PC3 and have reduced the Business Relationship and Project Delivery by a third to €600k.
- External consultant benchmarking (commissioned by BGN) concluded that BGN's software costs are significantly higher than their peers and we conclude that there is scope for negotiating reduced licence and support and maintenance costs. We have reduced the €3m annual software costs by one sixth of €500k.
- Vacancies are being covered by contract staff and there should be an incentive to fill these posts with permanent staff or conclude that they are not required going forward. Our analysis of external consultancy day rates has concluded that there is scope for negotiating reductions. We have allowed for a reduction of a further €750k.

- We have made a further efficiency adjustment of €500k to arrive at a starting position for PC3.
- The sum of the software and resource costs adjustment of €1750k has been apportioned on a pro rate basis across Service Delivery (€838k), Service Management (€419k), Infrastructure Management (€419k) and Architecture/ Information Security (€74k).

The following table is a summary of the normalised annual costs for Business Support Services.

Table 4.7 Business Support Services normalised annual cost

	2010/11 (€Ms)	2011/12 (€Ms)	Normalised Annual Cost (€Ms)
Finance	8.7	10.3	**8.7**
Regulatory and Commercial	4.1	5.5	**4.2**
Metering	4.1	3.9	**3.1**
IT and Telecoms	10.8	12.0	**9.9**
Facilities	6.1	6.5	**5.6**
Corporate	5.3	6.4	**4.0**
HR	2.9	2.8	**2.6**
Total	**42.1**	**47.3**	**38.1**

Source: Consortium

4.11. Pass-through costs

In the previous price control a number of items were considered to be outside BGN's control and have been treated as pass-through costs. However a cost sharing incentive was applied to certain categories. For example,

- If actual rates costs differed from the original allowance, then 50% of the difference (positive or negative) would be borne (or be to the benefit of BGN) and the other 50% would be passed on to customers;
- CO_2 is emitted from BGN compressor stations in Ireland and the UK. An annual allowance of CO2 is issued to each participating installation and the difference between the allowance and the total CO2 emissions must be purchased from the open market. For PC2 an agreed set of CO_2 volumes was established and a one year forward looking estimated price set. When closing, 50% of any savings/cost increase between the estimated and actual CO2 are passed through;
- The amount of CER levy imposed on BGN is a pass through cost as set by the CER and is split equally between Transmission and Distribution;

- The establishment and on-going costs of Gaslink were originally provided for in the 2007/8 – 2-11/12 Revenue Review Decision, based upon a 80:20 split between Transmission and Distribution. The actuals are reconciled and approved by the CER on an annual basis and any underspend is returned to the customers in the annual reconciliation process.

[redacted] We have left pass-through costs at their forecast 2011/12 levels pending further analysis of forecast opex (see Section 5). [redacted]

4.12. Gaslink costs

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 company employs 20 staff described as highly qualified and experienced. The company organisation replicates functions that exist in the structure of the new ITO. 80% of the costs or €12.2 million has been charged to Transmission opex in PC2 and the remaining €3 million to Distribution.

In July 2010 the Minister for Communications, Energy and Natural Resources decided that the ITO model be applied within BGE and as a result it is envisaged that Gaslink will become integrated into the ITO in 2012.

We have noted the apparent overlap in the department structures between the ISO and what resides in BGN at present. In its PC3 submission, BGN continues to show the ISO as a function within the ITO with modest cost reductions.

Given the apparent overlap and some uncertainty of how and when Gaslink's activities are to be fully integrated into the ITO and BGN Business Support Services in PC3, we have chosen to remove ISO costs from our normalised annual cost analysis pending our review of BGN's PC3 opex proposals. Our review of PC3 opex includes how activities currently undertaken by Gaslink should be reflected in PC3 opex allowances (see Section 5.4.6 below).

4.13. Normalised annual cost summary

The Transmission business is different from Distribution in that Transmission opex costs reflect the size and maintenance of the asset capital base and associated regulatory and safety requirements which change over time. In summary the key Transmission Direct opex cost drivers across the period have been:

- Growth in the Transmission Asset Base;
- Requirement to comply with the statutory and licensing requirements;
- Outsourced support services costs;
- Increased third party activity including surveillance, proximity encroachments etc; and

- Changes in risk profile of the asset base due to age, condition or environment, leading to an increase in maintenance activities.

The under-spend in Transmission opex relate primarily to (1) a revised subsea pipeline inspection schedule and (2) general efficiency savings such as Cathodic Protection, Inch compressor stations, development of a proximity infringement screening tool (PRIST), reduction in MOP reviews costs and optimising operational upgrades, project management, strategic outsourcing and procurement savings on contracts.

Hence given these characteristics it is not appropriate to be precise regarding establishing a normalised cost base in terms of a general annual efficient level of costs. In reality annual costs could differ greatly from one year to the next depending upon, for example, when subsea inspections are required and carried out, when major compressor station overhauls are scheduled and with cathodic protection scheduling.

Hence we have based our assessment of normalised on these considerations and hence in some cases as summarised below we have given ranges. However our examination of historic Transmission PC2 costs has enabled us to examine the level and changes in annual costs of BGN's Transmission business in order to give a firm foundation for examining PC3 forecasts. In particular costs have generally increased during years 2010/11 and 2011/12 and we have examined the reasons for these increases, taking into account cost drivers and the impact that changes in operational, regulatory and safety regimes from the earlier PC2 years.

The table below summarises our assessment and we have considered this further in reviewing BGN's PC3 opex proposals (see Section 5).

Table 4.8 Transmission Direct Opex last PC2 actual and forecast and PKF normalised annual cost

Transmission Direct Opex			
Activity	**Actual 2010/11 (€k)**	**Forecast 2011/12 (€k)**	**Proposed normalised annual cost(€k)**
TOTAL INCH	**879**	**841**	**850**
AGI	127	196	200
Compressor	4,093	5,730	5,300
Management	1,371	1,500	1,250
Pipeline	257	392	300
SCADA	290	421	280
Subsea Pipelines	704	3,397	700 – 3,400*
TOTAL Interconnector Opex	**6,841**	**11,636**	**7,555 – 10,255**
Less PTL Contributions	**-1,039**	**-1,351**	**-1,400**
AGI	7,194	6,774	6,100
Cathodic Protection	567	561	410
Grid Control	2,382	2,659	2,000
Management	1,339	678	740
Pipeline	2,062	1,926	2,000
Planning and Design	2,145	1,969	1,200
Safety and Quality	882	978	1,000
TOTAL Onshore Opex	**16,572**	**15,544**	**12,590**
Total Transmission Direct Opex	**23,253**	**26,671**	**19,595 – 22,295**

Data source: BGN PC3 PR012 and PKF normalised annual cost adjustments (indicates the range of expenditure depending on whether major inspections occur in the year)*

5. OPEX IN PC3

5.1. Overview

This section summarises our analysis of BGN's transmission opex and our proposals for the PC3 period.

BGN have stated that the key Transmission opex cost drivers over the PC3 period include:

- Growth in the transmission asset base and associated reinforcement programmes;
- Changes in risk profile of the asset base due to ageing, external conditions and environmental influences;
- Continuing to successfully operate the Network in severe weather periods;
- The requirement to comply with various applicable statutory and licensing requirements;
- Outsourced support services costs and relevant market movements;
- Increased third party activity including integrity, surveillance, proximity encroachments;
- The impact of refurbishment programmes such as the heating upgrade programmes;
- EU requirements to increase the range of product services, such as hourly balancing and reverse flow; and
- The changing nature of gas demand due to significant growth in the renewal power generation sector.

We have taken these aspects into account in our evaluation. In addition we have also taken into account Transmission capex forecasts and their impact on Transmission opex.

5.2. BGN's position

Table 5.1 summarises the main headings of opex for the Transmission business in comparison with the BGN PC3 forecast as amended by BGN's revised position of 15th March 2012, and shows the variance against the Consortium's proposed allowances based on our evaluated normalised cost levels from the historic opex review (see Section 4), and review of BGN's PC3 forecasts. As illustrated, BGN had forecast a total PC3 Transmission opex of €330 million which was subsequently reduced to €315 million.

Table 5.1 Transmission Opex for BGN Forecast PC3 by year and in total compared with Normalised PC3

2010/11 Monies €k	2012/13 Forecast	2013/14 Forecast	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	PC3 Total	Revised PC3 Total	Consortium for 5 Years	PC3 vs 5 year Consortium
Direct									
INCH	921	906	903	1,009	1,036	**4,775**	**4,775**	**4,775**	-
Interconnector Opex	11,211	11,704	12,815	13,264	17,380	**66,375**	**54,346**	**52,029**	-2,317
Less PTL Contributions	- 1,192	- 1,182	- 1,922	- 2,051	- 3,210	**-9,556**	**-8,589**	**-8,589**	0
Onshore	17,301	15,557	15,856	17,761	15,792	**82,267**	**81,030**	**73,777**	-7,253
Direct sub-total	**28,241**	**26,985**	**27,652**	**29,984**	**30,998**	**143,861**	**131,562**	**121,992**	**-9,570**
Miscellanous Adjustments	271	271	271	271	271	**1,355**	**1,355**	**1,355**	0
Innovation	1,662	1,978	2,006	2,066	2,082	**9,794**	**7,200**	**7,200**	0
Business Support Services	18,233	18,519	19,112	19,780	19,929	**95,574**	**95,248**	**86,263**	-8,985
Gaslink ISO	2,252	2,313	2,208	2,224	2,236	**11,234**	**11,234**	**9,550**	-1,684
Pass through	12,743	13,041	13,136	14,178	15,321	**68,418**	**68,418**	**68,418**	0
Grand Total	**63,402**	**63,107**	**64,385**	**68,503**	**70,837**	**330,234**	**315,017**	**294,778**	**- 20,239**

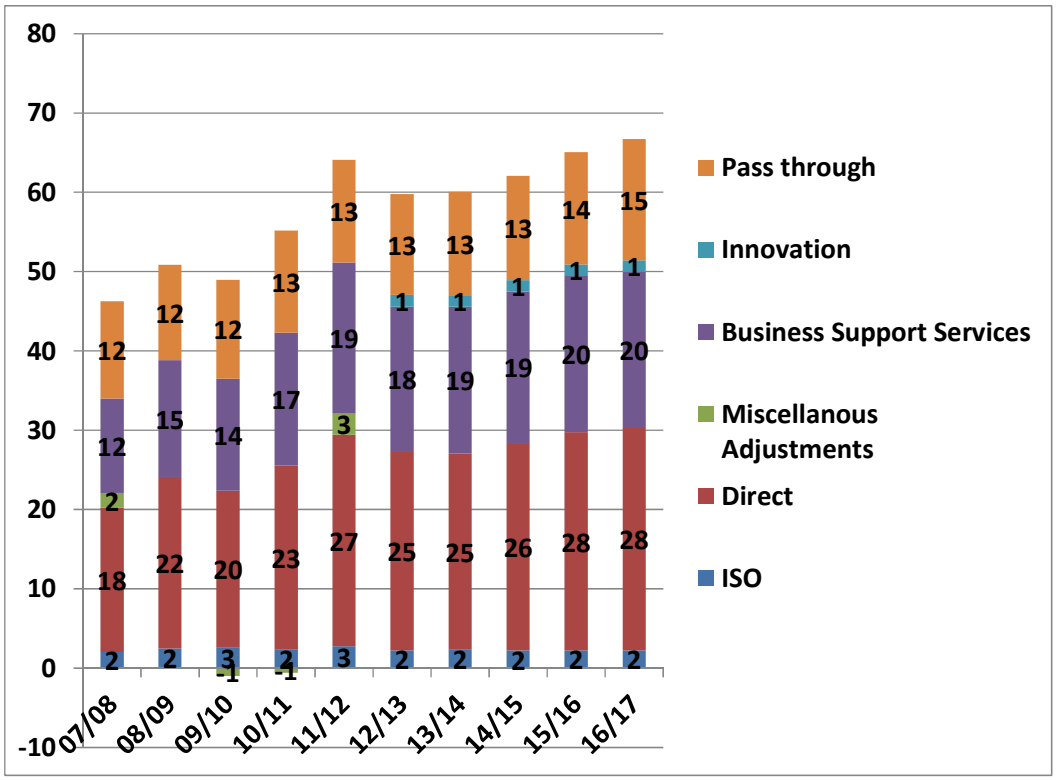
Source BGN PC3 submission, BGN Response to CER 'Minded to' position (15th March 2012) and Consortium

5.3. Consortium position

BGN has stated that, as a result of the NTP and ITO programme in PC2, it has the tools in place to realise operational savings across the organisation. However the headcount is projected to remain constant in PC3 and cost levels are projected to rise as shown in Figure 5.1 below. The figure has been updated to reflect BGN's revised PC3 submission and shows the annual forecast opex to be below the peak level for 2011/12 when a significant level of redundancy costs was incurred (shown under Miscellaneous Deductions and Charges).

Our conclusion from our review of historic transmission opex is that BGN has not been able to fully justify the substantial increase in operating costs following the two major programmes it has undertaken in PC2. There is also an absence of evidence of net savings being delivered by these initiatives in PC3. We have therefore not accepted the increased level of support cost opex presented by BGN. We have instead based our projections on the level of normalised annual expenditure (adjusted for inflation) discussed in Section 4 and made adjustments to reflect the evidence to support changes in costs going forward.

Figure 5.1 Opex expenditure profile over PC2 and PC3 €m



Source BGN's BPQ original submission updated to reflect revised submission

There have been significant organisational changes that have impacted the cost base and the allocation of costs in PC2. This structure, after accommodating the ITO changes, is expected to be in place throughout the PC3 period. Although BGN plan to adopt a new tariff structure that reflects their asset-based functional structure, our review has been based on the existing tariff structure and we have not been able to reflect our cost normalisation adjustments in BGN's preferred tariff structure as this would require the use of BGN's cost allocation routines. Although BGN's PC3 submission has focused on their new asset-based functional structure, they have provided comparatives based on the existing tariff structure and this has been the focus of our review of the PC3 transmission forecast.

5.4. Direct transmission opex spend

The table below (Table 5.2) summarises BGN's revised (15 March 2012) Direct Transmission Opex PC3 forecast spend compared to the PC2 actual spend, excluding PTL contributions together with the level of allowances we propose for PC3.

Table 5.2 Transmission Direct Opex for BGN PC2 and Forecast PC3 in total compared with Proposed PC3

Transmission Opex Activity	PC2	PC3	% change	Consortium Proposed PC3
Inch Opex	4,541	4,774	+ 5.1%	4,774
Interconnector Opex	43,174	54,346	+ 25.9%	52,029
Less PTL Contributions	-6,357	-8,589	+35.1%	-8,589
Onshore Opex	68,155	81,030	+18.9%	73,777
Total	**109,513**	**131,561**	**+21.0%**	**121,991**

Source: BGN PC3 submission and Consortium

Overall, BGN are facing some significant opex spends during PC3 and these are largely associated with both onshore and subsea pipeline inspections and surveillance, some of which are driven by compliance with standards and legislation and others which are driven by third party activity, notably offshore. Other areas of significant spend are associated with turbine major overhauls at Beattock and Brighouse Bay. However, there are some areas of increased opex that we consider are not explained or justified. We have set out below our conclusions with our rationale regarding establishing a reasonable PC3 Transmission opex cost base, and Table 5.12 at the end of this section details the consortium's proposed allowances(prior to applying an efficiency factor as discussed in Section 9) by Asset type:

Inch Opex

The primary BGN assets at the Inch Entry Point are the:

- Above ground installation (AGI) at the landfall of the Kinsale subsea pipeline. The key cost associated with the Inch AGI is the addition of gas odorant to the gas flow in order to provide the characteristic gas 'smell'. During PC2 the lower than expected flows from the storage facility due to the delayed expansion of the offshore gas storage facility by PSE Kinsale Energy resulted in reduced opex on odorant. BGN's document Asset Plan Installations provides details of the opex requirements for AGIs although there are no specific details provided that explain the 35% increase in operating costs for the Inch AGI. BGN have identified corrosion issues on exposed pipework supported by sliding metal supports but the remedial works associated with this issue appear in the Inch Capex forecast. There will also be some de-commissioning costs during 2015/16 associated with the wind-down of the Kinsale Offshore Storage Facility. The retirement of the Inch (Midleton) Compressors in 2015/16 explains the increase in compressor costs for the last two years of PC3.

- Midleton Compressor Station, which delivers gas from the Kinsale offshore gas storage facility into the BGN transmission pipeline system at Cork. The Midleton Compressor Station (MCS) opex is driven by the number of start/stops and machine running time. Capex spend on the MCS in the form of a Volume Control System (VCS) has resulted in a reduced number of start/stops and running hours and consequently improved reliability and reduced overall opex. BGN state – that optimum completion of the Cork uprating project resulted in a lower maintenance and operating cost at the Midleton Compressor Station and that a revised Volume Control System "has resulted in a reduction of running hours which has reduced the non-intrusive inspection scheduled in 2011 and as the machines are running for longer periods and are not subjected to the rigours of start-stops, the reliability of the turbines has increased." The result was a PC2 underspend of €1.53m.

  Based upon the BGN response we consider that the PC2 level of costs can be normalised at the 2010/11 and 2011/12 levels of around €850k, totalling €4.25m for PC3 compared to the BGN forecast of €4.577m. However we consider that the decommissioning costs with the Kinsale Facility and the increased costs of the Midleton Compressors in 2015/16 explains this increase and we therefore conclude that the PC3 forecasts overall do not appear unreasonable.

Interconnector opex

The key costs for Interconnector opex comprise:

- AGI's – 5 number block valve sites and 1 number pressure reduction/flow control facility at Twynholm in Scotland;
- Compressor Stations at Beattock and Brighouse Bay;
- Management costs associated with the interconnector assets;
- The UK onshore pipeline assets in Southwest of Scotland (SWOS);
- The SCADA system used for the control of the interconnector assets; and
- Costs associated with the operation and maintenance of the subsea pipelines (I.C.1 and I.C.2 between Scotland and Ireland).

These costs are offset by the contributions from Premier Transmission Limited (PTL), who share the SWSOS I.C.1 assets between Moffat and Twynholm, including a proportion of the operating costs of the Beattock Compressor Station.

Our conclusions regarding each of these opex costs are set out below:

AGI's: BGN state (PRO12 – page 8) that 'costs are associated with the maintenance and upkeep of 5 Block Valve Stations and one pressure reduction/flow control system'. For Interconnectors, 10% of Cost Centre 11358 SWSOS gets allocated to the 'Pipelines' tariff category and 5% get allocated to the 'AGI' tariff category. This cost centre includes the costs associated with Brighouse Bay

Compressor Stations which have overhauls scheduled in 2012, 2014, 2015, 2016 and 2017. In addition this cost centre bears the costs of the 10 year OnLine Inspections of the SWSOS pipeline in 2013. We recognise that the scheduled maintenance activities are not linear across years because the identification of overhauls differs year to year. Based upon the maintenance activities stated by BGN, the normalised in-year costs where overhauls are included is some €200k, based upon 2011/12 forecast costs.

BGN's overall PC3 opex forecast for AGI maintenance is forecast to increase and, in light of this, the increase of €560k (47% increase on the PC2 spend of €643k)) for Interconnector AGI's does not appear excessive given that this is the key BGN Transmission System Entry Point. Hence our overall conclusion is to acknowledge an increase in this tariff category and that the PC3 forecasts do not seem unreasonable given overhaul scheduling and planned online inspections.

Interconnector Compressors: The Beattock and Brighouse Bay compressor stations collectively comprise 13 no. gas turbine engines located at three compressor stations. All the turbines follow a similar design in that they are twin shaft mechanical drive units. The key cost drivers across the period are stated by BGN as:

- Annual planned and unplanned maintenance;
- Remote monitoring, OEM service and equipment and other support contracts;
- Number of stop/starts compressor operations;
- Operating running time;
- Compressor operations at demand limits; and
- 24/7 operation mode to transport gas from the Moffat entry point

Based upon BGN's explanations of cost drivers, including the increases in stop/starts and the cyclical nature of overhauls, the PC2 overspend is accepted resulting in a PC2 cost of €26.5m, equating to a normalised annual cost of c. €5.3m based upon 2010/11 prices. The increased compressor spend for PC3 (€30.3m compared to €26.5m for PC2) is essentially related to major overhauls of the Beattock and Brighouse Bay compressors in 2015/16 and 2016/17 and are based upon a Runtime/hours model developed by BGN which takes the projected demand of the network as agreed with the regulator and estimates the running hours on the turbines required to meet this demand. The schedule of compressor maintenance and approach to turbine overhaul costs is provided by BGN in the document Asset Plan Compressor Stations. Hence it is acknowledged that the schedule of overhauls performed in PC2 has no direct link to the planned schedule for PC3 as the overhauls are based upon the number of running hours performed. However we have questioned the BGN request for an allowance for contingency to cover the cost of an unplanned failure at each of the Scottish sites which was scheduled into the final year of PC3. BGN subsequently revised this position by removing the cost of the unplanned overhaul from the Beattock site based on the better reliability of this site which reduces operating cost by €2.4m over

the 5 year period. Based upon the BGN reconsideration, we consider that the PC3 forecasts are reasonable.

Management: PC2 management costs resulted in a slight underspend of €0.587m and hence indicates that the Interconnector Management costs can be managed within an overall tariff of €1.2m – €1.3m per annum. The PC3 forecast annual cost is around €1m pa which suggests efficiencies. Hence opex spend on this activity has shown a reduction of 25% (€6.9m in PC2 to €5.2m in PC3) and we consider that, based upon there being no significant changes in cost drivers and BGN's achievement of managing within this cost, the PC3 forecast is not unreasonable.

Interconnector Pipelines Inspection: Costs relate to the maintenance and operations of the onshore UK assets where maintenance of the network in the UK is provided by Scotia Gas Networks under a tendered maintenance contract with BGN. BGN's response to our question as to why these costs continue to increase in PC3 was that : "this cost centre includes the costs associated with the Brighouse compressor stations which have overhauls scheduled in 2012, 2014, 2015, 2016 and 2017." In addition, this cost centre has the costs of the 10 year OnLine Inspections of the SWSOS pipeline in 2013. It is recognised that these maintenance activities are not linear and reflect the planned overhaul schedules and the OLI inspection regime. However given the cost profile in PC2 we question whether the level of scheduled overhauls in PC3 is all strictly essential. Our view is that these costs should at least be maintained at the annual 2011/12 level of €392k and that the cost profile should reflect a normalised annual cost of no more than c€400k pa. We have also recommended to CER as part of our capex proposals that all opex (and capex) spend for the SWSOS system (Compressors and pipelines) be reviewed as part of a strategic Future Planning of the SWSOS system study. Hence it is considered that the PC2 tariff allowance is adequate to cover these costs with an average normalised cost of some €300k pa, representing an average of €200k – €400k, reflecting a non-overhaul year and an overhaul year respectively. This would give a PC3 allowance of €1.5m, rather than a BGN forecast PC3 cost of €2.755m.

Interconnector SCADA: This activity is concerned with the day to day system management including the daily physical and commercial operation of the transmission network. This covers all areas of the Network including South West Scotland, Sub Sea Interconnectors, Northern Ireland and the Isle of Man. Telemetry is used in Transmission including the interconnector to provide Supervisory Control and Data Acquisition (SCADA) services to Grid Control in Cork. Contract staff are used for specialist support. It is managed from a control room based in BGN Cork Headquarters and emergency response is also part of the responsibilities. There is a significant increase in SCADA opex between 2010/11 and 2011/12 (45%). Based upon the information provided, SCADA costs and Grid Control costs are both rising and hence it is difficult to detect any efficiencies being realised. Hence in our view the normalised costs should be c. €260k – €300k per annum. Taking an average annual cost of €280k, the PC2 cost would be c€1.4m. However BGN has provided only a limited explanation for the precise reasons for this under spend . BGN have not provided a compelling case for the 67% increase in spend on Interconnector SCADA from €1.53m in PC2 to €2.56m in PC3. We can see no significant change in the cost drivers and therefore we conclude that the PC3 allowance should be €300k pa, representing a total PC3 cost of €1.5m

Subsea Inspection pipelines: The Subsea Pipelines are concrete coated pipelines laid on the seabed some 1km apart to minimise risk of an incident affecting both pipelines. Subsea inspection is carried out bi-annually and the OnLine Inspection is carried out once every 10 years from 2013. Safety inspections of the pipelines are both internal (via on-line inspection, OLI) and external via subsea surveillance of the interconnector pipelines on the sea bed using a remotely operated vehicle (ROV) and divers. During April 2006, BGN reached agreement with the relevant safety authorities including the CER to reduce the requirement for sub sea inspections from annual to once every 2 years. This resulted in actual costs during the whole of PC1 of €7.38m. Hence the savings resulting from this new regime should reduce costs to below the PC1 levels and this has been achieved in PC2 with overall costs of €6.524m. The revised BGN forecast for PC3 is €14.897m. BGN attribute these additional costs to a combination of:

- Online inspections during 2012/13;
- Remotely operated visual subsea inspections;
- Subsea pipeline remedial works; and
- Surveillance works associated with the Wigtown Bay Offshore Wind Farm and Shale Gas exploration in Dublin Bay.

Given the critical importance of this system to security and the planned developments in the Irish Sea, we consider that the revised BGN PC3 forecast is reasonable, as we understand from BGN that more inspections will be needed.

PTL Contributions: Premier Transmission Limited (PTL) is the company that owns the pipeline from Twynholm in Scotland to Northern Ireland (SNIP). [redacted]

We have considered the revised BGN costs for Beattock costs and conclude that the BGN forecast PTL contributions for PC3 are reasonable.

Onshore Opex

AGI's: This activity is associated with the maintenance and operating costs of the AGI's (Above Ground Installations) throughout the network in Ireland and involves visual inspection, functional and equipment checks, condition monitoring and overhauls of operating equipment. The number of AGI's over PC2 increased to 178 AGI's in 2010 and 5 UGI's, an additional 10 AGI's added to the BGN network over the PC2 period, and therefore it is recognised that AGI costs would rise from 2010 as a result. However the rise in costs has been marginal resulting in BGN's PC3 forecast being only slightly higher than the PC2 forecast out-turn. Hence we consider that the PC3 forecasts are reasonable.

Cathodic Protection: Cathodic Protection (CP) is used to mitigate the effects of corrosion on buried steel pipework. It is a specialised activity and relatively labour intensive. The PC2 allowance

made provision for remedial works as well as monitoring. The CP monitoring and maintenance contract was awarded to a new contractor following a competitive tendering process in 2010, which also led to reductions in operating costs for CP maintenance and monitoring over PC2 rates. However CP costs in PC3 are forecast to increase from a PC2 level of €2m to nearly €7m in PC3. BGN justify this as 'the increase in PC3 is due to cost reallocation due to implementation of the HPUM'. We do not see this as adequate justification for such a significant cost increase. The Transmission Opex cost profile is not adequately explained. Hence our conclusion is that the PC3 allowance should not exceed €2.1m which equates to the actual BGN PC2 costs and reflects the expenditure shown in the submission.

Grid Control: Grid Control provides continuous system monitoring/operation and management of the day to day scheduling and after day allocation of Shipper gas flows in accordance with the commercial gas transportation requirements. This covers all areas of the Network including South West Scotland, Subsea connectors, Northern Ireland and the Isle of Man. Grid Control also acts as the Network Emergency Manager for the BGN Network. Grid Control staffing is 18 FTE's and this figure is not expected to change in PC3 as the current manning levels are considered adequate to cater for future physical and commercial development of the Network services. Based upon information supplied by BGN we see some justification for the level of cost increases shown in the last 2 years of PC2, but not to the extent of this magnitude in the last two years of PC2 (56% on the 2009/10 level).

Transmission Management: These costs reflect the management and administration of the overall Transmission business. We consider that the overall PC3 BGN forecast of €3.482, at 16% lower than PC2 does not appear unreasonable.

Onshore Pipelines: The BGN Transmission system consists of welded steep pipelines operating at pressures of up to 85barg with pipes ranging from 150mm to 900mm. The major function of these pipelines is to safely transport gas to pressure reducing stations and for delivery to the distribution system or to Transmission customers (mainly Power Stations) directly. These are the costs associated with surveillance and protection of buried pipelines. Activities include: online inspections, aerial surveys, ground patrols, leak surveys, third party surveillance and landowner visits and remedial works. BGN has an extensive OnLine Inspection programme and river flood plain surveys planned throughout PC3 as part of its compliance programme and we consider that this could justify the increased costs in the last 2 years of PC2 of €2.0m pa, which equates to a PC3 allowance of €10m. BGN state in their revised submission that in PC3 two online inspection batches totalling 1330km are scheduled which includes both interconnectors and in addition €1.2m relates to the use of new robotic inspection technology to inspect high risk urban lines which up until now were not inspect-able. Our overall conclusion is that the revised BGN PC3 forecast does not appear unreasonable.

Planning and Design: This activity includes non-capital elements of project work such as: system modelling and network planning and development, project design and estimation, managing projects, programmes and contracts, procurement of materials and services related to transmission projects such as regulatory assistance third party queries, GIS, records and data management, asset

programmes management, customer liaison and contract planning and management. Costs vary due to volume of third party activity, regulatory requirements, and changes in technical standards and compliance. Our conclusion is that we see no justification for any increases over and above the PC2 tariff allowance which should be more than adequate given the economic downturn. A normalised annual cost is considered to be €1.2m pa. This is reflected in BGN's PC3 forecast of €5.8m and therefore we consider the PC3 forecast to be reasonable.

Safety and Quality: These activities involve asset integrity, risk assessment and Safety Case compliance. Key activities include: operating pressure reviews and pipeline up-ratings, risk assessments, assessment and repair of defects, incident investigation, quality system management, emergency and crisis management and safety case management and reporting. Our conclusion is that the PC2 tariff allowance has been over estimated and that BGN should be able to manage this activity within the last year of PC2 forecast of some €1.2m per annum as a normalised cost based upon 2010/11 prices. This equates to a PC3 allowance of €6m which compares to the BGN forecast of €5.88m and therefore we consider the PC3 allowance to be reasonable.

5.4.1. Business support services

Business Support Services have been reviewed as a shared cost and the conclusions below are based on the total forecast which we have assumed (based on BGN's allocation for PC3) to be allocated 55% to Distribution, 40% to Transmission and the remainder to unregulated business.

There is a significant element of Group recharges included within Business Support Services and it is important to review these charges separately in order to assess the reasonableness of the Group reallocation in comparison with other network operators. BGN's submission includes €6m pa represented by €3m Group Finance, €2.5m Corporate and Secretariat and €500k for HR. We estimate that this represents approximately 1.5% of turnover compared with 0.75% to 1.7% for other network operators. Given BGN's intentions to be a median level operator we believe the level of Group Allocation should be reduced to 1.1% and reduced the level of allocation by 25% in the normalised calculations below.

The following tables compare recent actuals with BGN's request and our normalised annual cost for Finance, Corporate and HR showing group allocations and T&D's support costs separately.

Table 5.3 Finance Activities normalised annual cost

Finance					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Group Finance	3.0	1.7	1.6	3.0	2.2
BGN Gas Transportation Management and Finance	2.0	2.9	4.0	4.1	3.7
BGN Finance and Insurance	4.6	4.1	4.7	5.7	4.5
BGN and Group Finance	**9.6**	**8.7**	**10.3**	**12.8**	**10.4**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

For Finance our normalised annual cost from the historic opex review was €8.7m including the insurance function (staff costs, premiums and third party claims for self-insured excesses). We have revised the level of group allocation in line with the target level of 1.1% of turnover and increased this to €10.4m including an adjustment to reflect the increase in premiums over PC3. We have assumed that this remains constant throughout PC3.

Table 5.4 Corporate Activities normalised annual cost

Corporate					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Group Corporate and Secretariat costs	3.9	3.2	3.4	2.5	1.9
BGN Corporate and Secretariat costs	0.1	2.0	3.0	2.9	2.3
BGN and Group Corporate	**4.0**	**5.3**	**6.4**	**5.4**	**4.2**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

Corporate and Secretariat costs were forecast to be particularly high in 2011/12 with the establishment of the ITO. By the start of PC3 costs fall by €1m, primarily in the area of group allocation. Our review of historic opex concluded that a normalised annual cost of €4m was appropriate and we have increased this slightly to reflect the target level of group allocation. We have assumed that this remains constant throughout PC3.

Table 5.5 HR Activities normalised annual cost

Human Resources					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Group HR costs	2.0	0.9	0.5	0.5	0.4
BGN HR costs	0.8	2.1	2.3	2.8	2.4
BGN and Group HR	**2.8**	**3.0**	**2.8**	**3.3**	**2.8**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

HR is another area where there is a continuing allocation from Group after the ITO is established but this remains constant. BGN's HR cost increases from PC2 to PC3 by approximately €0.5m and with the additional workload associated with PCR11 (a new HR initiative discussed in Section 4) we have increased the normalised annual cost from €2.6m to €2.75m. We have assumed that this remains constant throughout PC3.

Regulatory and Commercial shows a 20% increase in costs from the end of PC2 to the start of PC3 and then remains fairly constant. The main increase is in Market Arrangements due to the absorption of the ISO (Gaslink). Gaslink costs are considered as a separate heading below. In our review of historic opex we concluded that a normalised annual cost of €4.2m was appropriate for Market Arrangements. Following our review of the forecast opex we have established that this represents the Gaslink costs that are shown separately in the tariff analysis and are therefore excluded from the normalised costs for Regulatory and Commercial below.

Table 5.6 Regulatory and Commercial Activities normalised annual cost

Regulatory and Commercial					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Commercial Operations	1.2	1.2	1.2	1.3	1.1
Shipper Services Development	0.6	1.1	1.3	1.1	1.0
Market Arrangements [1]	0.6	0.3	1.6	2.8	0
Shipper Services Operations	0.5	0.6	0.4	0.6	0.6
Shipper Services - Trading & Settlement	0.4	0.3	0.5	0.4	0.4
Capacity Planning	0.7	0.5	0.5	0.5	0.5
Total Regulatory and Commercial	**4.0**	**4.1**	**5.5**	**6.7**	**3.7**

Note 1: Expenditure associated with market arrangements is considered as part of the allowance for enduring Gaslink costs (see Section 5.4.6 below)

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

In other areas of Regulatory and Commercial costs our normalised costs from our review of Historic opex were generally close to the PC3 forecast costs requested by BGN and we have reflected this in the normalised costs shown above. We have assumed that this remains constant throughout PC3.

Networks Metering costs have nearly doubled from the end of PC2 (€3.8m) to the final year of PC3 (€7.3m) due to the anticipated rollout of smart-metering.

Table 5.7 Networks Metering Activities normalised annual cost

Networks Metering					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Master Data Services	3.7	3.7	3.3	3.6	3.2
Technical Services	1.1	0.5	0.6	1.1	0.9
Total Networks Metering	**4.8**	**4.2**	**3.9**	**4.7**	**4.1**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

Our historic opex assessment concluded that a normalised annual cost of €3.1m was appropriate. However in adjusting for the smart metering element that had been included in BGN's submission we had not added back the savings in traditional metering costs associated with smart metering and have increased our normalised cost estimates accordingly. We have assumed that this remains constant throughout PC3.

BGN's PC3 submission shows IT and Telecoms expenditure increasing from €11.9m to €15m (rising opex levels with increasing capex gives rise to an average for PC3 of €13.5m pa) from the end of PC2 to the final year of PC3.

Table 5.8 Networks IT Activities normalised annual cost €m

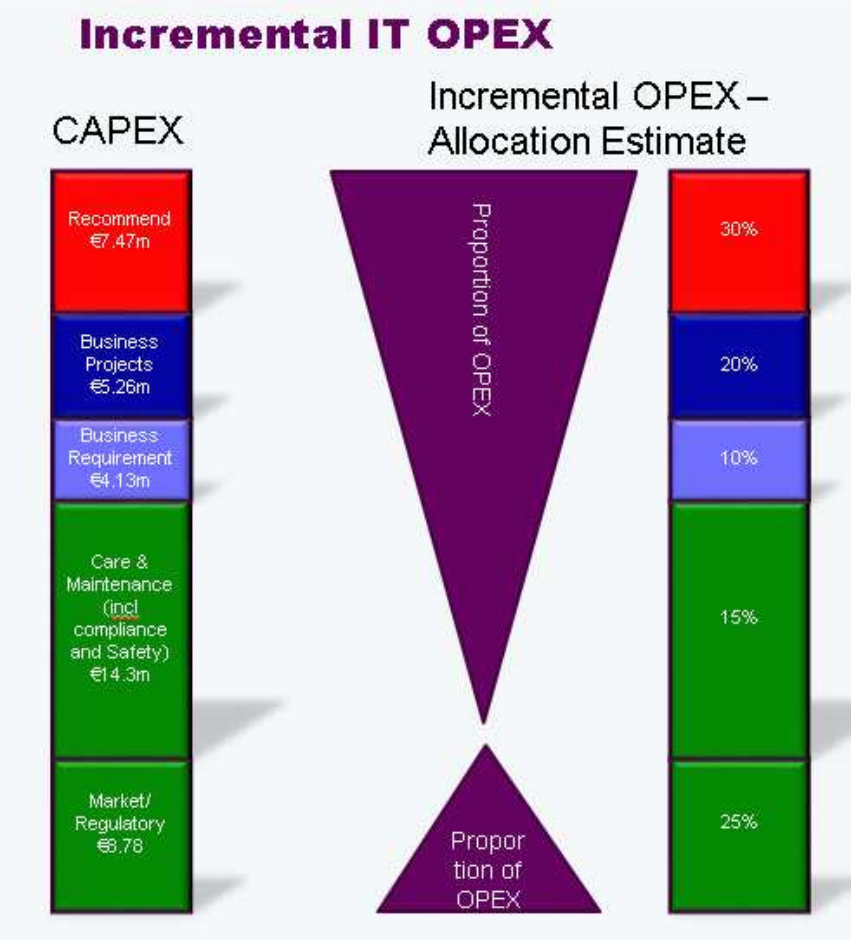
Networks IT					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Group allocation	3.7	1.1			
Networks IT	2.8	9.8	12.0	13.5	12.4
Total IT	**6.5**	**10.9**	**12.0**	**13.5**	**12.4**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

Our review of Historic opex reflected a proposed substantial reduction in the level of capital expenditure on the basis that major programmes had been delivered in PC2 and that capex and the associated opex should reduce and efficiency savings should be delivered. BGN subsequently put forward further submissions to justify the level of IT capex and opex .Following our assessment of the additional information provided by BGN we adjusted our normalised costs to the amount shown in the table above.

It is clear that although the NTP business case indicated a four year payback, it has had and will continue to have a significant adverse impact on IT opex with year on year increases proposed by BGN to maintain the new systems developed through the NTP. The diagram below is BGN's revised analysis of its IT capex highlighting the more discretionary projects towards the top of the diagram.

Figure 5.2 Capex and its impact on incremental Opex in PC3 €m



Source: BGN supplementary IT submission

In our assessment of the capex shown above and associated opex that should be allowed, "Market/ Regulatory and Care& Maintenance" total €23m and BGN should be challenged to deliver these at €22m. Of "Business Requirement" and "Business Projects" BGN should be challenged to deliver

key projects for €5.5m and for the "Recommended" category, projects allowed are €2.5m giving a total of €30m. At the same time we would expect opex to be in the region of the following:

Table 5.9 Networks IT proposed allowance €m

IT Operating Expenditure	2012/13 €m	2013/14 €m	2014/15 €m	2015/16 €m	2016/17 €m	Total €m
Baseline IT Opex	11.6	11.3	11.0	10.8	10.6	55.3
Driven by PC3 Capex	0.1	0.6	1.6	2.0	2.4	6.7
Total Opex (excl Smart Metering)	**11.7**	**11.9**	**12.6**	**12.8**	**13.0**	**62.0**

Source: Consortium

By the end of PC3, opex at this level remains within the BGN's external consultant's benchmark of 3.3% of turnover. The increasing level of incremental opex arises from the additional cost of operating the new IT systems that the capex programme represents.

Facilities costs are up 5% from the end of PC2 to the start of PC3 and rise by a further 2.5% over PC3.

Table 5.10 Facilities Activities normalised annual cost €m

Facilities					
Activity	**Actual 2009/10 (€m)**	**Actual 2010/11 (€m)**	**Forecast 2011/12 (€m)**	**BGN annual average PC3 (€m)**	**Consortium Proposed annual cost (€m)**
Facilities	4.9	6.1	6.5	6.1	5.7
Finglas Rent				0.8	0
Total Facilities	**4.9**	**6.1**	**6.5**	**6.9**	**5.7**

Source: BGN original and revised submission and Consortium normalised annual cost adjustments

Our normalised annual cost estimate from the review of historic opex was €5.6m and we have increased this to €5.7m to reflect BGN's additional operating forecast. There was some inconsistency in the way BGN presented the Finglas Rent cost (some of the cost in Facilities in some years and for other years shown separately from Facilities) and we have made this consistent across each year of PC3, adjusting the Facilities cost accordingly, and removed Finglas Rent from

Business Support Services on the basis that this is shown separately within the opex summary. We have assumed that this remains constant throughout PC3.

The following tables summarises the total Business Support Services cost allowances proposed by the Consortium and how we have apportioned the PC3 cost between Transmission, Distribution and other bodies not regulated by CER.

Table 5.11 Allocation of Business Support Services PC3 normalised costs €m

	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**

Source: Consortium

5.4.2. Innovation

There are significant amounts included in BGN's PC3 forecasts for Innovation and we have proposed that the scope of the proposed Innovation Projects should be reviewed and prioritised as a separate exercise. Our separate published report on incentives considers the 'lessons' from the GB experiences of the Innovation Funding Incentive programme launched by Ofgem in 2008. Based on similar allowances for other network companies, we have allowed Innovation of €1.6m per annum, and €8m for PC3 in total. These amounts have been shown separately in the opex cost summaries rather than as part of Business Support Services. In BGN's revised submission this proposed allowance was accepted but apportioned in a different manner between Transmission and Distribution. €160k pa was allocated by BGN to Distribution and the remaining €1,440k pa to Transmission. We have accepted this allocation.

5.4.3. Further analysis of costs (including staff cost analysis)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

5.4.4. Miscellaneous charges and deductions

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 relating to the Network Services Works Contract. 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.

5.4.5. Pass-through costs

We have considered BGN PC3 forecast for Rates, the CER Levy and CO2 emissions and, based upon the information provided and with PC2 comparatives we conclude that the forecast costs appear realistic based upon on the available information.

5.4.6. Gaslink costs

In our review of historic opex there was some uncertainty over whether the Market Arrangements costs within Business Support Services represented the full cost of the absorbed Gaslink organisation given that CER has been asked by BGN to continue with a separate Gaslink allowance until the ISO has been dissolved. Initially we had removed this cost and following further clarification we have assumed that any separate ISO allowance that is granted by CER will need to be adjusted for in the T&D allowances which we have now included. Gaslink ISO costs are shown separately in the opex summaries for T&D. Given the similar organisational structure of the ISO, we have assumed for PC3 that there is scope for further rationalisation of the activities of the ISO. We have reduced the enduring Gaslink costs request by 15% and allocated this 20% (€477k pa, €2,387 for PC3) to Distribution and 80% (€1,910k, €9,549k for PC3) to Transmission.

5.5. Summary

A summary of the annual allowances proposed by the Consortium for Transmission opex costs for PC3 is given in Table 5.12 below.

Table 5.12 Transmission Consortium Proposed PC3 Annual Costs

Category	2012/13 Consortium	2013/14 Consortium	2014/15 Consortium	2015/16 Consortium	2016/17 Consortium	Total Consortium
Direct						
AGI	42	36	34	47	39	198
Compressor	879	870	869	962	997	4,577
INCH	**921**	**906**	**903**	**1,009**	**1,036**	**4,775**
AGI	215	232	238	215	305	1,205
Compressor	4,467	4,641	6,563	6,645	7,975	30,291
Management/Est	980	1,015	1,026	980	1,160	5,161
Pipeline	300	300	300	300	300	1,500
Barclays lease buyout	- 2,525					- 2,525
SCADA	300	300	300	300	300	1,500
Subsea	3,205	3,325	2,548	3,005	2,816	14,899
Interconnector Opex	**6,941**	**9,813**	**10,976**	**11,445**	**12,856**	**52,031**
Less PTL Contributions	**- 1,192**	**- 1,182**	**- 1,922**	**- 2,051**	**- 2,243**	**- 8,589**
AGI	6,759	5,964	6,214	6,933	6,063	31,933
cathodic Protection	410	410	410	410	410	2,050
Grid Control	2,500	2,500	2,500	2,500	2,500	12,500
Management	702	695	695	695	695	3,482
Pipeline	2,267	2,319	2,536	2,555	2,441	12,118
Planning and Design	1,241	1,180	1,154	1,130	1,108	5,812
Safety and Quality	1,182	1,183	1,173	1,173	1,173	5,883
Onshore	**15,061**	**14,251**	**14,681**	**15,396**	**14,390**	**73,778**
Direct sub-total	**21,732**	**23,788**	**24,638**	**25,799**	**26,039**	**121,995**
Finglas Rent	271	271	271	271	271	1,355
Miscellanous Adjustments	**271**	**271**	**271**	**271**	**271**	**1,355**
Business Support Services	**16,894**	**17,013**	**17,372**	**17,452**	**17,532**	**86,263**
Innovation	1,440	1,440	1,440	1,440	1,440	7,200
Direct total	**40,337**	**42,512**	**43,721**	**44,962**	**45,282**	**216,813**
ISO	**1,910**	**1,910**	**1,910**	**1,910**	**1,910**	**9,549**
CO2	28	47	65	26	- 35	130
Rates	122	125	133	141	149	669
INCH	**149**	**171**	**198**	**166**	**113**	**798**
CO2	770	705	271	161	515	2,422
Rates	4,221	4,432	4,654	4,886	5,130	23,324
Interconnector Opex	**4,991**	**5,138**	**4,925**	**5,047**	**5,645**	**25,746**
CO2	- 133	- 140	- 27	- 41	- 119	- 460
Rates	- 799	- 827	- 856	- 886	- 917	- 4,287
Less PTL Contributions	**- 933**	**- 967**	**- 883**	**- 928**	**- 1,036**	**- 4,747**
CER Levy	1,320	1,320	1,320	1,320	1,320	6,600
Rates	7,215	7,379	7,576	8,572	9,278	40,020
Shared Direct	**8,535**	**8,699**	**8,896**	**9,892**	**10,598**	**46,620**
Pass through	**12,743**	**13,041**	**13,136**	**14,178**	**15,321**	**68,418**
Grand Total	**54,989**	**57,462**	**58,767**	**61,049**	**62,512**	**294,779**

Source: Consortium

6. OUTTURN CAPEX IN PC2

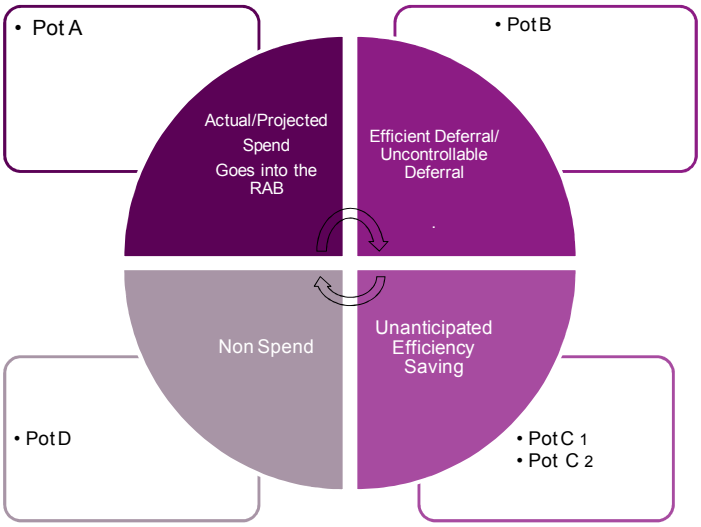
6.1. Overview

This section reviews BGN's PC2 transmission capex and summarises our proposed adjustments to BGN's PC2 close out position.

6.2. Regulatory guidance and reporting

BGN has reported its historic capex variances (under and over spend against the CER's PC2 allowances) according to its interpretation of the regulatory guidance in the PC2 decision paper (see our incentives, outputs and uncertainty mechanisms report for further discussion). BGN has determined its transmission variances as follows, with capex variances split in to 3 categories ("Pots"). Pot A represents the actual spend, with the variance from allowances being split between Pot B, C and D, as illustrated in Figure 6.1 below.

Figure 6.1: BGN analysis of transmission capex variance



Source: BGN

Pot B identifies the variances attributable to projects that were Efficiently Deferred. Examples of these include:

- Identified I/C connections including:
  - Gas to Amgen, Carrigtwohill
  - Gas to IDA, Mullagharlin

- AGI Capacity Upgrades
- Reinforcement projects (e.g. Gas to IDA, Mullagharlin)
- Future works / operation for the interconnector

Pot C identifies the variances attributable to efficiency savings achieved on projects that have been completed or are under construction:

- Pot C1 efficiency savings relate to savings realised pre the setting of the Control Budget and are referred to as scope savings i.e. CER Allowance versus BGN Control Budget.
- Pot C2 efficiency savings relate to savings realised post setting of the Control Budget and are referred to as efficiency savings i.e. BGN Control Budget versus Actual Cost of the project.

Pot D identifies the variances which are classed as Non-Spend and where revenue is not retained on these variances.

For Pot D BGN also refer to the term "Negative Non Spend". This is where the scope of a project/tariff category increased over that envisaged when the allowance was set, and the resultant cost of the increased scope is offset against non spends in other areas and included as a negative in Pot D (i.e. "Negative Non Spend").

Once expenditure is allocated to "Pots" this has implications for the allowed revenue BGN can recoup from its customers because of the under or over spend.

The actual wording of the guidance for PC2 is provided in Annex A while Table 6.1 gives a summary of the implications of different allocations of *under spend* for allowed revenues.

Table 6.1: Revenue implications of transmission capex categories

Pot	Category	Revenue implications
Pot B	Deferral	Where a deferral is judged to be efficient BGN will retain the depreciation and return each for the project in PC2, but no value for the project will be added to the starting RAB for PC3.
Pot C	Efficiency savings	BGN will retain the benefits of this under spend for 5 years from the date of inclusion in the RAB. The actual rather than forecast capex incurred is put in the RAB at the end of the 5 years.
Pot D	Non-spend	For capex variances classified as non-spend, the return and depreciation earned by BGN in PC2 will be clawed back in lower revenues in PC3.

Source: Consortium

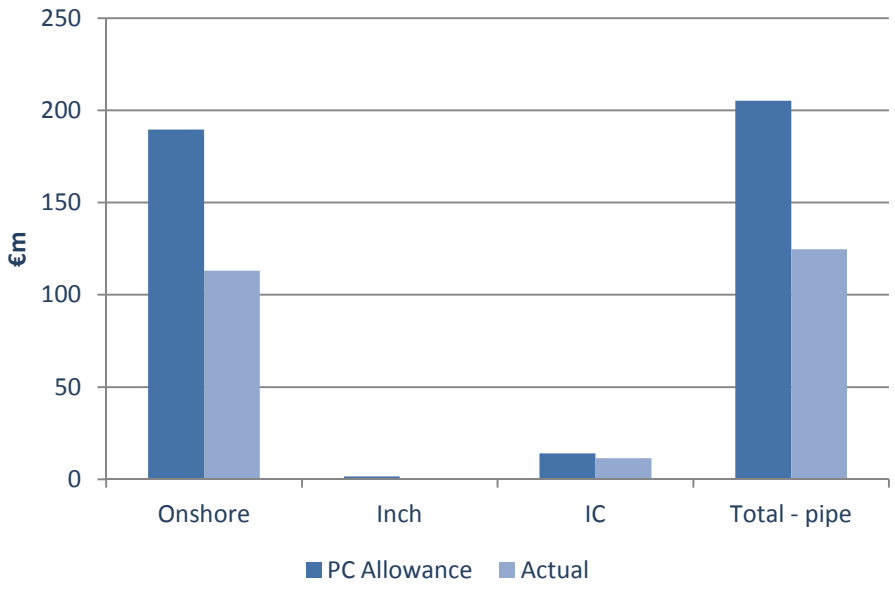
The guidance also highlights there where an *over spend* arises because a project was completed at higher cost than anticipated when the control budget was set, CER would not generally expect to remunerate BGN for financing these higher capex costs in PC2, but would consider where all the actual capex incurred should be included in the starting RAB for PC3. It was for BGN to demonstrate that the higher actual capex was efficiently incurred.

Finally for the transmission price control, CER highlighted that it would take a project by project approach to assessing under and overspends of transmission capex to reflect the nature of the projects involved. This approach recognised that at the time of the determination many of the projects had not been scoped out, rather an allowance under certain categories of transmission spend had been made.

6.3. Summary of capex outturn

Figure 6.2 shows outturn transmission pipeline capex including PC2 and the final year of PC1 (2006/07 gas year) where a forecast was made for setting the PC2 review. It illustrates an overall under spend against the transmission tariff allowance.

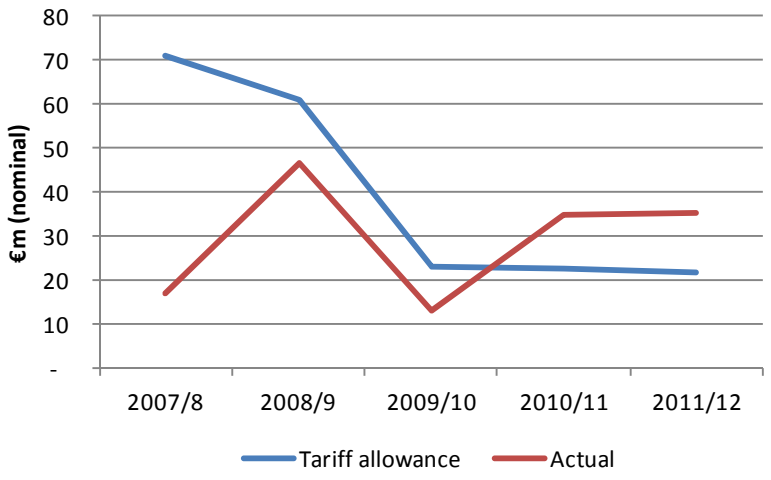
Figure 6.2: Revenue implications of transmission capex categories



Source: BGN and Consortium

Figure 6.3 shows actual and projected transmission capex in each year of PC2 relative to the original (inflated) PC2 allowances. This provides a clearer picture of how capex has actually been incurred by BGN over the control period.

Figure 6.3: BGN transmission capex variance



Source: BGN and Consortium

Projects delivered during the price control period focused on three key areas:

- **Growth capex**: resulting from the expansion of the gas network to new towns, power stations and industrial and commercial clients.
- **Reinforcement capex**: to ensure that the network continues to operate efficiently, effectively and safely.
- **Refurbishment capex**: a programme of reviewing and refurbishing the network to ensure it continues to comply with legislation, technical standards and codes of practice.

Examples of growth related capex projects have included Phase II and Phase III new towns, construction of a new pipeline from Midleton compressor station to Aghada, a new pipeline for Endessa gas-fired station at Great Island, a new pipeline to Dublin Airport and a new AGI on Spencer Dock to supply Dublin Docklands.

Reinforcement capex has included reinforcement of the southern part of the transmission system, by twinning the existing Curraleigh West to Midleton Pipeline and building a new pipeline from Lochcarraig Lodge to Midleton, reinforcement of the Wilton Area in Cork City and reinforcement of the Ballynora to Legenaghmore pipeline and AGI.

Examples of refurbishment capex include a number of pipeline replacement projects along with refurbishment of the Royal Oak AGI in Dublin and upgrades to water-bath heaters at various AGI locations. As with reinforcement and growth related pipeline capex, this is a sample of projects completed by BGN over the 5-year control period.[11]

[11] BGN (2011): 'Price Control 2 Executive Summary'

Transmission capex also includes non-pipeline investments. This relates to Information Technology (IT) and the capital works associated with the provision of facilities and fleet to support BGN's transmission activities.

6.4. BGN position

BGN's BPQ look back for PC2, sets out the company's view of the revenue it believes should be returned to customers in PC3 arising from the under spend in PC2 transmission capex. Table 6.2 below provides a summary of how BGN has analysed transmission related capex in PC2 according to the "Pots" system outlined above.

Table 6.2: Transmission related capex (PC2 and 2006/7) – actual prices

Category	Tariff	Actual	Variance	Scope	Efficiency	Efficient deferral	Non-spend
Pot	**n/a**	**Pot A**	**n/a**	**Pot C**		**Pot B**	**Pot D**
Onshore	189.6	113.1	76.5	8.9	21.3	27.3	18.9
Inch	1.6	0.1	1.5	-	-	1.5	-
IC	14.0	11.4	2.5	-	0.2	3.3	-1.0
Total - pipe	**205.1**	**124.7**	**80.5**	**8.9**	**21.5**	**32.1**	**17.9**
Non-pipe	29.9	35.2	-5.3	-5.3	-	-	-
Total	**235.1**	**159.9**	**75.2**	**3.6**	**21.5**	**32.1**	**17.9**

Source: BGN

Overall there was a €75m positive variance in networks capex which BGN suggest mainly relates to a combination of efficiency savings and efficient deferral of transmission projects arising from changing circumstances.

Based on this allocation of capital spend, BGN has proposed that the amount of revenue to be refunded to gas transmission customers as a result of unspent capex amounts to €4.27m. It has offset this amount by revenue to be earned beyond the PC2 period under the capex rolling incentive mechanism (amounting to €1.75m).

Combining the two, BGN's net position for the transmission control give back to consumers, amounts to €2.52m (including an adjustment for interest).

6.5. Approach to outturn capex assessment

We have approached our review of BGN's historic capex as follows:

- review of transmission capex drivers in PC2 and transmission system gas demand during this period (for each of the key gas demand sectors);
- review differences between capex allowances for PC2 and actual (or projected) capex incurred in PC2 by BGN's transmission business;

- review of BGN's historical BPQ submission, in particular its proposals for revenue giveback in PC3;
- where there has been over or under spend against allowances, provide a view of how this should be adjusted for by CER at PC3.

For our assessment of capex under spend and how, in particular, projects that did not go ahead as planned (deferral) should be treated in the PC3 revenue giveback calculation, we sought to analyse BGN's proposals according to the following assessment criteria:

- Controllability – was the deferral driven by BGN decision making or events outside of BGN's control?
- Proportionality – are project savings (and the revenue benefits) proportionate given the operating environment and regulatory framework in PC2?

For the controllability criteria, we focused on the customer role – i.e. how did network users or specific project sponsors affect the project deferral or scope decision.

Where CER had provided a decision or instruction to BGN to go ahead with a transmission capital project we also took this into account in our assessment of how the capex variance should be treated at the PC3 review.

Based on this approach and principles, we have then reviewed BGN's actual capex and its proposals for PC2 RAB additions. This informs the CER's calculation of the opening RAB for the PC3 period. We have then gone on to review the separate (although interlinked) issue of BGN's transmission revenue give-back proposals related to efficient deferral and non-spend of capex.

6.6. Consortium view

6.6.1. RAB additions

From a purely technical perspective, we regard the majority of actual pipeline capex spend for Onshore, Inch and Interconnector categories as justified and necessary.

However, we believe the 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.

We also believe the regulatory guidance for PC2 was clear that CER would take a project by project approach to assessing under and overspends in transmission. See Annex A.

Finally the guidance was also clear that the burden of proof lay with BGN 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.

Our proposals for adjustments to BGN's RAB addition position are summarised in Table 6.3 below. This is illustrates that our view of efficiently incurred capex is very close to BGN's position following a number of helpful clarifications raised by the operator on its outturn capex. However, we have concluded that small negative efficiency variances on certain areas of transmission spend should be excluded from the starting PC3 RAB.

Table 6.3: Transmission capex for inclusion in the RAB

	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	Total
BGN position	**10.81**	**11.84**	**20.16**	**47.25**	**45.98**	**35.11**	**171.15**
Negative efficiency [1]	-	-	-	-	-	-0.2	-0.2
Total adjustments	-	-	-	-	-	-0.2	-0.2
Consortium position	**10.81**	**11.84**	**20.16**	**47.25**	**45.98**	**34.91**	**170.95**

Notes:

Note 1: With no better information the negative efficiency variance has been allocated to 2011/12

We have accepted the principle that actual spend in excess of the tariff allowance should be allowed in the starting RAB for PC3 where a general transmission category (bucket) allowance was provided at PC2 (e.g. onshore refurbishment). However, we highlight that a revenue cap was the form of regulatory control for transmission in PC2.

As well as providing an incentive to find efficiency savings the revenue cap was an incentive for BGN to *control* capex costs. Indeed, BGN was allowed a pre-tax return on capital of 5.2% by the CER to reflect the financing and operational risks of its transmission and distribution networks businesses including the delivery of capital projects.

This means, in our view, that while BGN should achieve cost recovery for efficiently incurred capex (through additions to the RAB) it should not expect PC2 *financing* costs associated with the higher than initially forecast (at the determination) cost to necessarily be funded by network users. We consider this principle further as part of the discussion of revenue clawback.

6.6.2. Clawback

As with the RAB additions, we have reviewed BGN's proposals for revenue clawback based on a review of project and category outturn. Based on our review, we believe that BGN should give back a larger quantum of revenue to customers than was proposed in its PC3 submission.

As regards overspends, we believe the regulatory guidance is clear for both transmission and distribution that network users should not be expected to remunerate BGN for *financing* higher capex costs in PC2 whether scope or efficiency variances. CER put in place a revenue cap in PC2 to provide an incentive for BGN to find efficiency savings *and* control capex costs.

Therefore, in our view, and consistent with the PC2 regulatory guidance, we recommend that the CER's revenue give-back calculation *exclude* the return on capital BGN believe they are due on higher actual capex in PC2 even where the actual capex is included in the starting RAB for PC3.

As with our proposals on RAB additions we believe this provides an appropriate incentive and precedent to BGN to control capex costs within its price control allowances. This position balances the principle of cost recovery with the regulatory incentive properties of the price control.

Accepting the principle of cost recovery where actual higher capex is efficiently incurred, BGN should receive the PC2 depreciation due on projects where there was an overspend and the actual capex is included in the starting RAB for PC3.

As regards efficient deferrals, we repeat the point we make in our published incentives report, that an "incentive is an incentive" and while BGN has been able to outperform the allowances through deferral of specific capex projects, consumers in the long run will benefit from these savings - this is the objective of the incentive.

On the other hand, part of the revenue from deferrals which BGN proposes to retain from PC2, relates to the economic downturn and events where the project sponsor (i.e. customer) made a commercial decision not to proceed with a particular project. While avoiding these works has been efficient, it may be arguable whether the savings were all *controllable* by BGN.

Having reviewed the CER's guidance on deferral incentives and mirroring our proposals for overspends, we recommend BGN be allowed to retain a proportion of the revenue from efficient deferrals although less than BGN's proposal which requests retention of the revenue on all efficient deferrals proposed in its PC3 submission.

Our revised proposals amount to 41% of BGN's total request. Again we believe this provides an appropriate incentive and precedent to BGN to seek efficient deferral of capex projects in future price control periods.

Where we have disallowed efficient deferrals, and propose the CER seek a clawback of the revenue, this is generally because we believe the project was intricately linked to the customer rather than BGN demonstrating efficient decision making.

For negative non-spends[12] our proposal is that changes in scope generally related to *customers* having changed their requirements should be allowed. However, areas where the negative non-spend applied to a general category (bucket) allowance – for example, general refurbishment – and where BGN's proposed increase in the tariff allowance is in cases significantly more than the original allowance, the evidence we have been provided we believe does not justify the revenue BGN believe they should receive arising from those projects.

However, recognising the principle of cost recovery of actual incurred capex which we have applied to our assessment of RAB additions, negative non-spends which we have disallowed we propose BGN be allowed the *depreciation* arising from the revised tariff allowance but not the return on capital arising for the change in scope.

[12] This is where a capex allowance was set by CER, BGN argue the scope increased in PC2 and therefore the allowance they should be reviewed against should also be increased.

We believe this strikes a pragmatic balance of cost recovery and an incentive to control capex costs within the price control allowances. Our proposals on revenue give back are summarised in the tables overleaf.

Table 6.4: Consortium proposals for negative non-spends

	€000	Consortium view whether to allow the negative non-spend
Gas Supply to IDA	27	✓
Gas to Tynagh Energy	61	✓
Huntstown Power Phase II	423	✓
Spencer Dock AGI	342	✓
General refurbishment	7,089	×
Future projects	1,001	×
Brighouse Bay IC2 Bypass	382	✓
Reinforcement	583	×
Facilities	343	×
Total	**10,252**	
Total allowed negative non-spend		**12%**

Table 6.5: Consortium proposals for transmission efficient deferral

Element	Consortium view whether an efficient deferral?	% of total efficient deferral request
Identified large I&C connections:		
Gas Supply to IDA	×	1.5%
Gas to Amgen	×	7.6%
Gas to IDA	×	17.7%
Cherrywood AGI	×	0.1%
Future AGI capacity upgrades	×	32.1%
Code compliance	✓	18.5%
Limerick optimisation	✓	7.7%
Gas Quality	✓	4.6%
Beattock Volume Control	✓	1.4%
Future works / operations	✓	3.9%
IC performance testing	✓	2.9%
Noise reduction	✓	2.1%
Total allowed efficient deferral		**41.0%**

7. CAPEX IN PC3

7.1. Overview

This section summarises our analysis of BGN's transmission capex and our proposed allowances for the PC3 period.

7.2. BGN position

Table 7.1 summarises BGN's distribution capex proposals.

Table 7.1: BGN proposed transmission capex

Category	12/13	13/14	14/15	15/16	16/17	Total
Onshore						
Large I&C Connections	308	1,500	2,500	3,000	3,000	10,308
New Towns	815	1,217	-	-	-	2,031
Innovation	462	500	1,162	525	25	2,674
Refurbishment	23,859	17,027	16,329	17,785	15,646	90,645
Reinforcement	6,525	6,773	10,173	20,023	28,795	72,290
Total Onshore	**31,969**	**27,017**	**30,164**	**41,333**	**47,466**	**177,948**
Interconnector						
Reinforcement	3,100	3,822	3,706	3,511	3,271	17,410
Refurbishment	46,139	46,939	800	1,500	1,500	96,879
Total Interconnector	**49,239**	**50,761**	**4,506**	**5,011**	**4,771**	**114,289**
Inch						
Refurbishment	675	880	565	560	210	2,890
Total Inch	675	880	565	560	210	2,890
Non-pipe						
IT	5,453	4,482	4,096	3,022	2,930	19,982
Facilities	1,145	765	923	878	658	4,370
Total non-pipe	**6,598**	**5,247**	**5,019**	**3,899**	**3,588**	**24,352**
Total PC3 capex	**88,480**	**83,906**	**40,254**	**50,803**	**56,034**	**319,478**

Source: BGN

7.3. Consortium comments and position

7.3.1. Growth pipeline capex (Onshore)

The consortium has reviewed BGN's submission for forecast Transmission growth capex for the period 2012/13 to 2016/17 and reached the conclusion that the forecast volumes for Large I&C Connections are overly-optimistic based on the outcome of PC2. We have therefore revised downwards BGN's projections to what is, in our view, 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. New Towns Connections have been removed on the basis that no CER regulatory approval has been received and Innovation spend has been removed as a capital allowance and is only included as opex (see note 3 below).

Our proposed onshore growth capex allowances are summarised in Table 7.2. For each category of growth pipeline capex, we have shown BGN's proposed allowance in the top row (in black) while the consortium view is in the bottom row (in blue).

Table 7.2: Proposed onshore growth capex allowances

€m	2012/13	2013/14	2014/15	2015/16	2016/17	Cum
Large I&C Connections [1]	308	1,500	2,500	3,000	3,000	10,308
	300	400	600	1,000	2,000	4,300
New Towns Connections [2]	815	1,217	-	-	-	2,031
	815	-	-	-	-	815
Innovation [3]	462	500	1,162	525	25	2,674
	-	-	-	-	-	-
Total	1,585	3,217	3,662	3,525	3,025	15,013
	1,115	400	600	1000	2,000	5,115

Notes:

[1] Large I&C Connections are over-optimistic and brought in line with PC2 actual outcomes.

[2] The New Towns expenditure for Cavan/Cootehill (€815k) is approved but the €1.217m relating to Wexford has not received CER approval and so is removed

[3] Innovation is treated purely as opex and so is removed from capex.

7.3.2. Non-growth pipeline capex (Onshore, Interconnector and Inch)

In terms of Transmission Non-Growth capex, we are broadly in agreement with BGN's level of forecast spend, with the following exceptions:

- The €5m of unspecified Transmission Reinforcement spend has been reduced to €2.5m, conditional on BGN's clear specification of what this reinforcement entail;
- The SWSOS Twinning Pipeline spend of €91.8m has been removed (until the outcome of the current consultation on this issue is known); and

- The €5m proposed spend on the "Future Planning of the SWSOS Network" has been reduced to €1m for the purposes of a more strategic study of the SWSOS compressor and pipeline system at the start of PC3.

Overall, we have proposed a 51% reduction from a BGN proposed spend of €280.114m to €137.033m as shown in the table below. As with growth related pipeline capex, the top row for each of spend (shown in black) provides the BGN proposed allowance, while the bottom row (shown in blue) provides the consortium view.

Table 7.3: Proposed non-growth capex allowances (onshore, interconnector and Inch)

€m	2012/13	2013/14	2014/15	2015/16	2016/17	Cum
ONSHORE:						
Refurbishment	23,859	17,027	16,329	17,785	15,646	90,645
	23,859	17,027	16,329	17,785	15,646	90,645
Reinforcement [1]	6,525	6,773	10,173	20,023	28,795	72,290
	6,574	6,804	3,264	5,728	2,718	25,088
Sub-Total Onshore:	30,384	23,800	26,502	37,808	44,441	162,935
	30,233	23,731	19,693	24,013	19,864	115,733
INTERCONNECTOR:						
Refurbishment [2]	3,100	3,822	3,706	3,511	3,271	17,410
	3,100	3,822	3,706	3,511	3,271	17,410
Reinforcement [3]	46,139	46,939	800	1,500	1,500	96,879
	-	-	-	-	-	0
SWSOS – Future Study	1,000	-	-	-	-	1,000
Sub-Total Interconnector:	49,239	50,761	4,506	5,011	4,771	114,289
	4,100	3,822	3,706	3,511	3,271	18,410
INCH:						
Refurbishment [4]	675	880	565	560	210	2,890
	675	880	565	560	210	2,890
Sub-Total Inch:	675	880	565	560	210	2,890
	675	880	565	560	210	2,890
Total Non-Growth	80,298	75,441	31,573	43,379	49,422	280,114
	35,208	28,533	23,864	27,584	21,845	137,033

Notes:

[1] €5.00m for 'Transmission Reinforcement' is unspecified and has been reduced to €2.5m conditional on BGN's clear specification of what this reinforcement entail.

€44.70m for Curraleigh West to Goat Island pipeline reinforcement has been removed (€6.7m removed from 2014/15, €13.4m removed from 2015/16 and €24.6m removed from 2016/17 respectively) in light of uncertainty of PSE Kinsale Energy's plans for the future operation of the gas storage facility.

[2] €17.41m for Beattock Compressor refurbishment should be reviewed within the context of the *'Future Planning of the SWSOS Network'* (see Note 3 below).

[3] €5.00m for '*Future Planning of the SWSOS Network*' has been reduced to €1m. We recommend CER bring forward this strategically important study to the start of PC3.

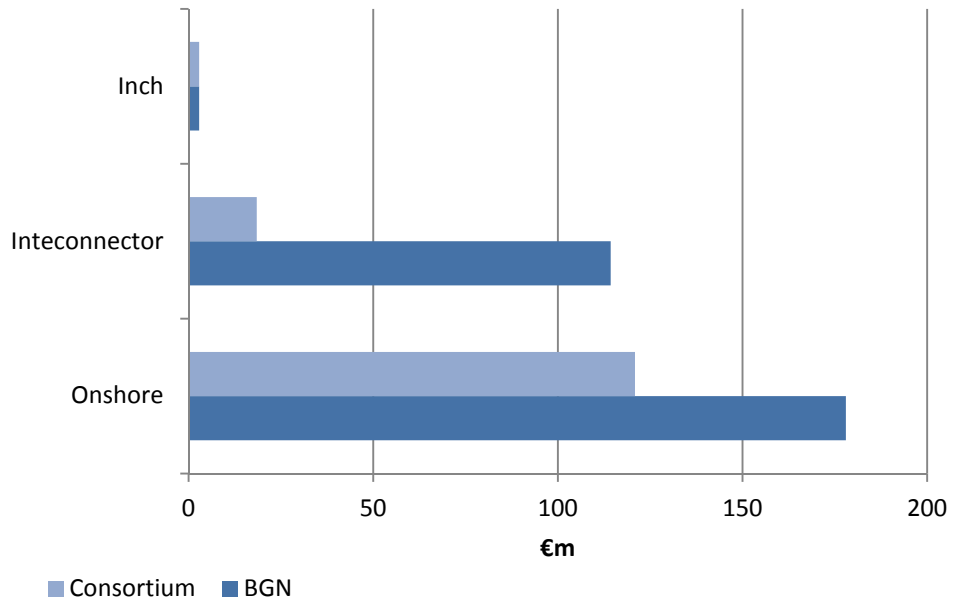
Additionally, the construction of the Cluden to Brighouse Bay Pipeline at €91.8m can be deferred to the start of PC4 depending on the decision by the CER and the outcome of the consultation process and '*Future Planning of the SWSOS Network*' study. If the pipeline is deemed as required during PC3, we would suggest that the Capex be re-profiled as €45.94m in each of years 2015/16 and 2016/17.

[4] €2.89m for Inch should be included but reviewed in light of developments at the Kinsale Energy gas storage facility – i.e. if the facility is decommissioned the spend is deemed necessary. If the life of the facility is extended, the annual allowance should be reviewed and reduced.

7.3.3. Overall reduction transmission pipeline capex

Figure 7.1 illustrates our proposed PC3 pipeline capex allowances for Onshore, Interconnector and Inch relative to BGN's PC3 business plan position. It shows our proposals result in large reductions to the capex plans submitted by BGN.

Figure 7.1: Comparison of consortium and BGN proposed transmission pipeline capex



Source: Consortium and BGN

The drivers of the pipeline capex variance have been described in the subsections above. In some cases this is because we have adopted different assumptions from those used by BGN in its capex plans (for example, large I/C connections).

In other cases, there is a variance between ourselves and BGN because while we consider there to be a technical case for the investment, either the project has not received regulatory approval (e.g. new towns) or there is uncertainty of certain aspects of the business and/or technical case that supports including the capex in the PC3 allowances. Where this is the case, we have removed the capex from our PC3 allowances.

In a number of cases, we have also removed, or significantly reduced, pipeline capex where the purpose of the expenditure was left unspecified by BGN in its PC3 submission.

Given the approach we have adopted for pipeline capex, it is likely that the CER and BGN will need to agree a process where additional expenditure removed ex ante at the PC3 review, can be included in the tariff allowances over the course of PC3 as the technical case or regulatory approval of projects is certain.

7.3.4. Non-pipeline capex

Facilities

BGN's proposed facilities capex is set out in Table 7.4.

Table 7.4: Proposed facilities capex

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Facilities	1,145	765	923	878	658	4,370

Source: BGN

In our view BGN's PC3 submission does not provide sufficient evidence to support nearly €4.4m in facilities capex.

We have therefore reduced BGN's transmission facilities capex by 25% to a total of €3.3m for the PC3 period.

Information Technology

BGN is seeking an IT Capital Allowance of €39.9m during the PC3 period (transmission and distribution). The allowance excludes Common Arrangements for Gas (CAG) and European Transmission System Operators Group (ENTSOG), which will be agreed separately with the CER. IT capex specifically for transmission is €19.98m as summarised in Table 7.5.

Table 7.5: Proposed IT capex

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
IT	5,453	4,482	4,096	3,022	2,930	19,982

Source: BGN

In their original submission BGN categorised their PC3 Capex spend into the following four areas

- **Regulatory / Market Driven** – projects that will be required to meet regulatory and market driven requirements over PC3 with costs of €8.8m. The main areas of the proposed spend is in the area of enhancements to Retail and Wholesale Market systems and the introduction of Market facing Online Customer Services.
- **Run** – projects that will be required to maintain existing IT applications and the projects required to support BGN business in optimising the execution of its business processes with costs of €12.9m.

- **Grow** – projects covering the new technology investments required to support the growth and expansion of the BGN business with costs of €14.1m.
- **Transform** – projects that will change the way in which the business currently operates, with a focus on improving both operational capabilities efficiencies and the organisational effectiveness from these investments. These costs are €4.1m. Enhancements to the existing wholesale Market systems will be required to support a number of mandatory market driven changes.

BGN have not at this stage prepared detailed investment appraisals nor have these projects pending approval moved to even the early stages of the procurement process.

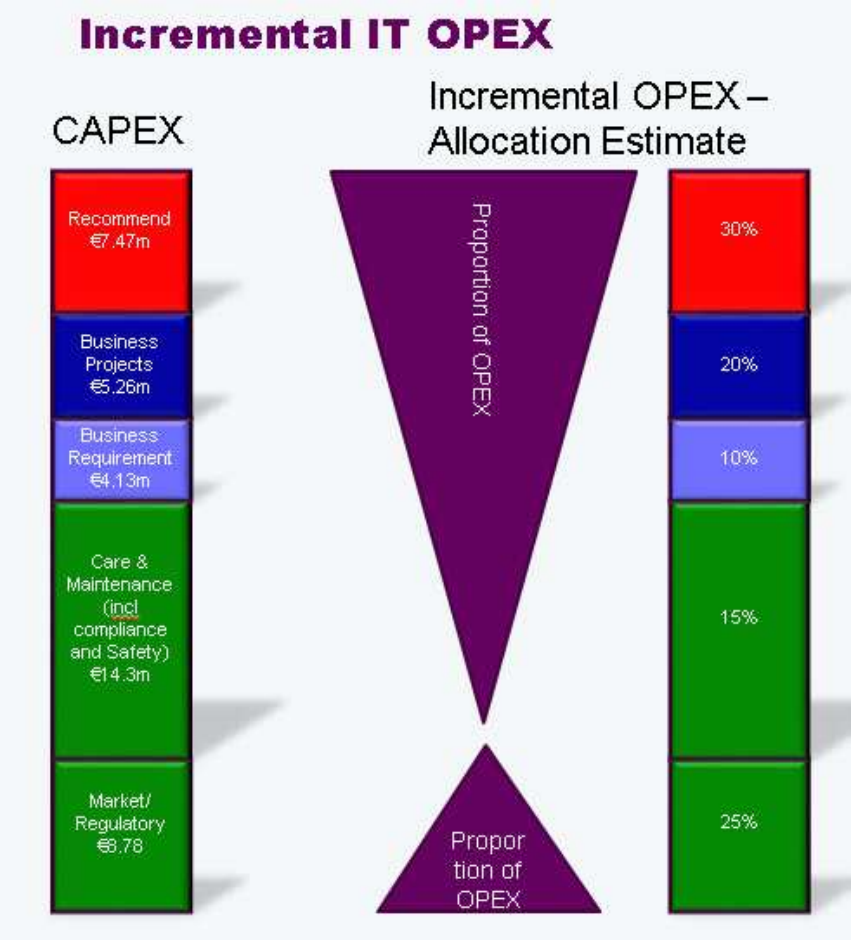
BGN have provided detailed value statements and financial analysis to support the costs above and have cited increased opex costs to maintain the system improvements of €3.6m, alongside estimates of cost savings of €3.0m and avoided costs (opex costs that BGN claim it would incur if the capex projects were not approved) of €2.5m.

Whilst the €3.6m of increased opex costs is included in the opex cost forecast for PC3, the corresponding saving of €3.6m has been included in part. BGN has confirmed that approximately €1m of savings were not included and emphasised that €0.5m of savings are for Shippers to realise and are not BGN savings. The project that gives rise to these savings for the Shippers is the Short Term Network Modelling Solution at a cost of €1m.

Initially, our draft report on non-pipe capex proposed a substantial reduction in the level of IT capital expenditure on the basis that major programmes had been delivered in PC2 and that Capex and the associated opex should reduce and efficiency savings should be delivered. BGN subsequently put forward further submissions to justify the level of IT capex and opex .Following our assessment of the additional information provided by BGN, we increased the proposed Capex allowances to €30m over PC3 as discussed below.

It is clear that although the NTP business case indicated a four year payback, it has had and will continue to have a significant adverse impact on IT opex with year on year increases proposed by BGN to maintain the new systems developed through the NTP. Figure 7.2 (overleaf) is BGN's revised analysis of its IT capex highlighting the more discretionary projects towards the top of the diagram.

Figure 7.2 Capex and its impact on incremental Opex in PC3 €m



Source: BGN supplementary IT submission

In our assessment of the capex categories shown above and associated opex that should be allowed, "Market/ Regulatory and Care& Maintenance" projects total €23m and BGN should be challenged to deliver these at €22m. Of "Business Requirement" and "Business Projects" BGN should be challenged to deliver key projects for €5.5m and for the "Recommended" category, projects allowed are €2.5m giving a total of €30m. Using BGN's estimated opex associated with their proposed 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.

Table 7.6: PC 3 Proposed Forecast Capex to be allowed in 2010/11 prices €k Total T&D

	2012/13	2013/14	2014/15	2014/15	2015/16	Total
Regulatory/ Market Driven	2,397	1,970	1,800	1,328	1,288	**8,783**
Run	3,539	2,910	2,659	1,961	1,902	**12,971**
Grow	3,858	3,171	2,898	2,138	2,073	**14,138**
Transform	1,111	914	835	616	597	**4,073**
TOTAL PC3 BGN PROPOSED	**10,905**	**8,965**	**8,192**	**6,043**	**5,859**	**39,965**
PROPOSED ALLOWANCE	**8,200**	**6,700**	**6,200**	**4,500**	**4,400**	**30,000**

Source BGN IT Capex submission adjusted by consortium

7.4. Proposed allowances

Our proposed capex allowances for IT and facilities are set out in Table 7.7 below. We have reduced BGN's forecasts for facilities capex by 25 per cent and have made a number of adjustments to its proposed IT capex. We have shown BGN's proposals in black while the consortium's proposed allowances are in blue.

Table 7.7: Proposed facilities capex

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Facilities	1,145	765	923	878	658	4,370
Facilities	859	574	692	659	494	3,278
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	**6,598**	**5,247**	**5,019**	**3,899**	**3,588**	**24,352**
Total	**4,959**	**3,924**	**3,792**	**2,909**	**2,694**	**18,278**

7.5. Summary

Our proposed transmission capex allowances for each year of PC3 and each category of transmission capex are summarised in Table 7.8.

Table 7.8: Proposed PC3 transmission capex allowances

Category	12/13	13/14	14/15	15/16	16/17	Total
Onshore						
Large I&C Connections	300	400	600	1,000	2,000	4,300
New Towns	815	-	-	-	-	815
Innovation	-	-	-	-	-	-
Refurbishment	23,859	17,027	16,329	17,785	15,646	90,645
Reinforcement	6,574	6,804	3,264	5,728	2,718	25,088
Total Onshore	**31,548**	**24,231**	**20,193**	**24,513**	**20,364**	**120,848**
Interconnector						
Reinforcement	3,100	3,822	3,706	3,511	3,271	17,410
Refurbishment	-	-	-	-	-	-
SWSOS - Future study	1,000	-	-	-	-	1,000
Total Interconnector	**4,100**	**3,822**	**3,706**	**3,511**	**3,271**	**18,410**
Inch						
Refurbishment	675	880	565	560	210	2,890
Total Inch	**675**	**880**	**565**	**560**	**210**	**2,890**
Non-pipe						
IT	4,100	3,350	3,100	2,250	2,200	15,000
Facilities	859	574	692	659	494	3,278
Total non-pipe	**4,959**	**3,924**	**3,792**	**2,909**	**2,694**	**18,278**
Total PC3 capex	**41,282**	**32,857**	**28,256**	**31,493**	**26,539**	**160,426**

8. ITO COSTS

8.1. Overview

The Third EU Directive has required the unbundling of network operations from the energy businesses. BGN sought legal advice on how to comply and following discussions with CER and its parent Department has commenced changes that will result in the establishment of an independent subsidiary owned by BGE as an ITO.

This section covers the key points arising from our analysis of the work done by BGN to implement the EU Third Directive towards the end of PC2. This work within BGN was known as Project 3. First we summarise the conclusions of our analysis of ITO setup costs. We then present our views on the ITO opex costs that arose in PC2 but were not anticipated at the time the PC2 opex transmission and distribution allowances were set.

8.2. ITO setup costs

8.2.1. Overview of project

The key points to note are:

- The project continues to progress and the costs are being carried as capital work in progress at Group level pending approval of the project cost and project completion.
- BGN has taken the appropriate steps, including legal advice, to comply with the Third Directive and has obtained both Irish and UK approval to the ITO option they have implemented.
- The chosen option was to establish an ITO covering both Ireland and Northern Ireland and the core part was the separation of previously shared Human Resources, IT, Finance and Corporate Service functions.
- These have been 'lifted and shifted' over a period of 18 months in the latter half of PC2. All organisation designs, responsibilities, and existing processes were documented in detail by external consultants.
- The overall cost of the exercise was €34.6m and the focus of the effort was on very precise organisation separation, process and procedural documentation, change management and IT enablement of the shared services and shared ITO functions that needed to be separated and transferred.

BGN state that the project will result in redesigning over 1,000 business and finance processes, the re-absorption of Gaslink, the ISO which was established at the end of PC1 as an independent subsidiary of BGE, the transfer and transition of 120 roles impacting 300 staff and the separation of IT, facilities and offices so that BGN has its own support functions.

8.2.2. Our conclusions

Costs of over €34m to move 120 staff appear excessive. A more realistic figure would be in the order of some €24m which still recognises the complexity of the regulatory separation and is based upon the Consortium's experience of similar transitions – thus transition costs would appear to be overstated by some €10m

When we discussed the allocation of ITO costs with CER it was noted that the scope of the ITO project has addressed the networks business in Northern Ireland as well as in Ireland and that the Irish consumers should not incur costs that relate to benefits for consumers in Northern Ireland. How this issue is to be resolved has not been addressed in this paper.

8.2.3. Observations

We understand that the functions contained in the ITO are Asset Management, Regulation and Commercial (including market arrangements), Health, Safety, Quality and Environment (HSQE), Workflow, Service Delivery, and Corporate and Support Services (HR, Finance, Procurement, and Supply Chain).

BGN 'lifted and shifted' 120 people who were largely in a shared service centre covering both the Energy and Network business. They were moved to a single location just covering the network business.

This was a large project involving over 1,000 business and finance processes, 120 people involving 300 roles, physical separation of IT facilities and offices, managing over 20 stakeholder groups, and separation of hardware, software and infrastructure for over 20 applications and 400 licences. Detailed cost information was provided by BGN on all these aspects and monitored throughout the programme.

Whilst staff covered 3 jurisdictions UK, Ireland and Northern Ireland, the understanding was that all the staff were based in Cork and were being moved from one office to another. The cost of moving the 120 people (including associated changes in systems) was €34 million or €280,000 per capita. On the face of it this seems a very high per capita ratio.

To assess the level of the ITO project costs proposed by BGN, the Consortium drew on its direct experience of transactions including demergers and outsourcing. One particular project in 2009, involved 40 people and related processes and systems and moving them from 4 locations to 1. The work covered the full range of back-office support functions and entailed:

- Project management and change management involving many different stakeholders in three countries
- Establishing a new shared service centre with significant IT investment in hardware, software and telephony for the new staff
- Detailed process mapping and work instructions

- Work shadowing and training of 40 new staff
- Addressing European legal, tax, employment, and accounting issues
- Redundancy and outplacement for UK staff, many of whom were long serving
- HR and union consultation for affected staff
- Post go live monitoring and synergy assessment

All this was done in less than 6 months including set up with transfer of roles during a 2 month work shadowing period.

Transition was done with minimum disruption to the operations of the business and achievement of all project milestones, on time, to quality and surpassing business case projections. It cost some €3.2 million equating to some €80,000 per capita. Whilst not an identical project we believe it indicates that at €280,000 per capita the BGN ITO cost appears high.

Other UK public sector shared service project examples in our experience – both are project cost only and exclude benefits-are:

€32 million costs for moving 900 staff covering over 30 National Health Service areas with considerable complexity and significant IT investment and union issues, excluding redundancies. The per capita cost here was about £35,000

€3 million for 70 staff in the transport sector involving centralisation, a move from 6 locations, IT investment, and redundancies. An approximate per capita cost here was £43,000.

So whilst every project is different, the above per capita cost ratios are indicative that such projects can be done at lower cost. All the above projects had positive benefits cases as well.

BGN consider that they did project management well with external consultants payments being tied to milestone achievements and deadlines, which we understand were all met.

Success factors in these types of projects and enablers for reducing costs in the Consortium's experience include:

- Clear tasking of staff with rapid on-boarding, and off-boarding plus prudent use of senior staff and deskilling tasks or skill transfer (e.g. process mapping) so that either incumbent staff or very junior contractors can be used.
- Using an optimum mix of consultants, in house, own staff and staff in role to execute the work.
- Reliance wherever possible on in house legal, tax, accounting and HR team to handle the contractual, VAT and Corporation Tax, and Employment issues. They incorporated the work in their day job rather than being assigned to the project.
- Use of existing process maps and procedure guides.

- Acknowledging that there were some significant upfront 'quick win' simplifications and cost savings on the way through reengineering processes.
- Taking the opportunity to use the process mapping and ways of working review to identify further synergies to be implemented post go live.

Our sense is that BGN could have achieved efficiencies during the project, and been more pragmatic about how they did the work.

The Consortium's experience is that by using independent contractors and outsourced staff reductions in rates can be achieved – for instance with outsourced off shore staff 60% or so less than UK or Ireland [redacted]

Documenting 1,000 processes for 120 staff appears high, especially as some such as asset management and environment are likely to be network only in the first place. There are likely to have been some existing maps for audit or QA certification purposes. In addition a very comprehensive approach was taken.

A more cost effective approach might have been to prioritise by criticality according to separation criteria and address those processes likely to be more customer focused and prone to a separation challenge. The other processes may not have needed to be mapped or could have been done by incumbent staff.

It also seemed a missed opportunity not to use the analysis and insight to plan for future efficiencies and cost reductions in the functions impacted by the ITO, as typically these types of transition can offer 15% to 20% cost reductions according to Shared Services Industry protocols stemming from process automation and redesign.

8.2.4. Summary

In summary we are of the view that savings of some €10m could have been achieved in project costs if a more prudent and practical approach had been adopted – when compared to other projects of a similar scale and complexity

Even doubling a more reasonable per capita cost of €80,000 (to €160,000) to allow for the fact that the BGN project involved establishing both the ITO, whilst also ensuring that the residual functions were properly organised at Group level, and allowing a further 25% for complexity and the special legal, stakeholder management and governance considerations, there appears to be no compelling evidence to support a cost in excess of €200,000 per capita or €24m in total.

8.3. ITO opex

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.

We have concluded that the additional ITO costs in PC2 could have been contained. Going forward we have reduced operating costs by significant amounts reflecting savings that are achievable both in these additional ITO operating costs and the wider network operating costs that should have been reduced during PC2. However, for the purpose of this additional allowance, we recognise that these costs have been incurred by BGN and have reduced the disallowance by 12.5 per cent as illustrated in Table 8.1 below.

Table 8.1: Additional 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

8.4. Summary

Our proposals for PC2 ITO setup and opex costs are summarised in Table 8.2 below.

Table 8.2: Allowances for ITO establishment in PC2

€m	**BGN**			**Consortium**		
	Dist.	**Trans.**	**Total**	**Dist.**	**Trans.**	**Total**
ITO setup costs	4.7	18.8	23.5	2.7	10.8	13.5
ITO PC2 opex	2.0	8.0	10.0	4.8	3.5	8.3

9. BENCHMARKING

9.1. Overview

This section summarises the work that the consortium carried out to benchmark BGN's transmission activities.

9.2. Approach

There were three main elements to this work:

1. A review of BGN's cost trends;
2. A review of BGN's BPQ submission; and
3. A review of trends in other regulated sectors.

BGN engaged Juran, an oil and gas benchmarking company to provide benchmarking on BGN's operational performance.

9.3. Findings

Juran benchmarked BGN's transmission operations, for its 2009 financial year, against seven European comparators. The report noted that analysis has been conducted independently by Juran.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Juran's report makes the following key points following its comparative analysis of BGN's transmission business activities:

- The efficiency of BGE's gas transmission system operations and maintenance is variable between activity areas.
- BGE is a leading performer in terms of both Compressor spending and staffing levels.
- Performance effectiveness, which describes the quality of the outputs from BGE, including safety, environmental impact, compressor reliability, and service quality, was very strong in all areas.
- Emissions were an exception to this performance which are comparatively high due to the requirement for high pressure lift and the associated high compressor running hours.
- BGE's safety performance (injuries), delivery point availability and interruptions were amongst the best and they were the leading company in terms of compressor reliability, which is commendable given the exacting operational demands being placed upon the compressor fleet.
- Some effectiveness performance gaps were evidence, most notably in the area of emissions. However, Juran note that this might be expected for emissions given the high compressor running hours and pressure lift necessary to meet operational demands.[13]

Juran summarise their report as follows:

> "BGE operate a relatively short transmission system that transports low volumes of gas over medium distances at very high pressures over parts of the network. The network is relatively young and the downstream distrbiution network is still in development. The high pressures are achieved using compressors which are online continuously in order to meet demand. Within these unique operating conditions, BGE appear to deliver a very efficient and effective Compressor O&M service."

One benchmark for the potential efficiency that could be achieved by BGN are those attained by companies in other regulated sectors that are based on network infrastructure services. This comparison can be justified on the basis that these companies undertake similar activities and are subject to economic regulation too. As part of our own analysis we have undertaken a review of Real Unit Operating Expenditure (RUOE) trends achieved by BGN and other sectors such as gas transmission and distribution in GB.

[13] Juran (2011): 'An independent analysis of BGE Gas Transmission Operational Performance'

We have also considered ongoing efficiency gains, or frontier shift, improvements over time in the industry's production function. This has included an assessment of the Republic of Ireland's historical productivity performance, supplemented with a view on other regulator's previous decisions on the scope for ongoing efficiency.

However, a top-down benchmarking of transmission performance of this kind is difficult. We therefore consider that the bottom-up analysis provides the best estimates for BGN's relative performance. We still consider though that there is scope for ongoing efficiency gains and we consider that an efficiency target of 1% per annum is achievable by BGN to reflect such future (i.e. frontier shift alone) efficiency gains.

9.4. Conclusions

We recommend that the CER seek to apply an additional adjustment to controllable transmission opex in PC3 (i.e. to the normalised opex allowances proposed in Section 5) of 1 per cent per annum to account for future efficiency gains. This is reflected in our transmisison opex allowances summarised in Section 10.

10. CONCLUSIONS

10.1. Summary of proposed opex allowances

Table 10.1 summaries our proposed transmission opex allowances. This includes a 1% year-on-year reduction in controllable opex.

Table 10.1: Consortium proposed transmission opex

Category	12/13	13/14	14/15	15/16	16/17	Total
Direct						
AGI	42	35	33	45	37	192
Compressor	871	853	843	924	948	4,439
INCH	**912**	**888**	**877**	**969**	**985**	**4,631**
AGI	213	228	231	206	290	1,168
Compressor	4,422	4,549	6,368	6,383	7,584	29,306
Management/Est	970	995	996	941	1,103	5,005
Barclays lease buyout	- 2,525					
Pipeline	297	294	291	288	285	1,456
SCADA	297	294	291	288	285	1,456
Subsea	3,173	3,259	2,472	2,887	2,678	14,469
Interconnector Opex	**6,847**	**9,618**	**10,650**	**10,994**	**12,226**	**50,334**
Less PTL Contributions	**- 1,180**	**- 1,158**	**- 1,865**	**- 1,970**	**- 2,133**	**- 8,306**
AGI	6,691	5,845	6,029	6,660	5,766	30,992
cathodic Protection	406	402	398	394	390	1,989
Grid Control	2,475	2,450	2,426	2,401	2,377	12,130
Management	695	681	674	668	661	3,379
Pipeline	2,244	2,273	2,461	2,454	2,321	11,754
Planning and Design	1,228	1,156	1,119	1,086	1,054	5,643
Safety and Quality	1,171	1,159	1,138	1,127	1,115	5,709
Onshore	**14,911**	**13,967**	**14,245**	**14,789**	**13,685**	**71,596**
Direct sub-total	**21,489**	**23,314**	**23,907**	**24,782**	**24,763**	**118,255**
FRS Pension Adjustment	-	-	-	-	-	-
Redundancy Charge VS/VER	-	-	-	-	-	-
CO2 Incentive	-	-	-	-	-	-
Gaslink Recon'n/ rate of return	-	-	-	-	-	-
Finglas Rent	271	271	271	271	271	1,355
Miscellanous Adjustments	**271**	**271**	**271**	**271**	**271**	**1,355**
Shared Costs Allocated	-	-	-	-	-	-
Networks IT	-	-	-	-	-	-
Insurance	-	-	-	-	-	-
Third Party Claims	-	-	-	-	-	-
Facilities	-	-	-	-	-	-
Shared Direct	-	-	-	-	-	-
Transportation	-	-	-	-	-	-
Business Support Services	**16,725**	**16,674**	**16,856**	**16,764**	**16,673**	**83,693**
Innovation	1,440	1,440	1,440	1,440	1,440	7,200
Direct total	**39,925**	**41,700**	**42,473**	**43,257**	**43,146**	**210,502**
ISO	**1,891**	**1,872**	**1,853**	**1,834**	**1,816**	**9,266**
CO2	28	47	65	26	- 35	130
Rates	122	125	133	141	149	669
INCH	**149**	**171**	**198**	**166**	**113**	**798**
CO2	770	705	271	161	515	2,422
Rates	4,221	4,432	4,654	4,886	5,130	23,324
Interconnector Opex	**4,991**	**5,138**	**4,925**	**5,047**	**5,645**	**25,746**
CO2	- 133	- 140	- 27	- 41	- 119	- 460
Rates	- 799	- 827	- 856	- 886	- 917	- 4,287
Less PTL Contributions	**- 933**	**- 967**	**- 883**	**- 928**	**- 1,036**	**- 4,747**
CER Levy	1,320	1,320	1,320	1,320	1,320	6,600
Rates	7,215	7,379	7,576	8,572	9,278	40,020
Shared Direct	**8,535**	**8,699**	**8,896**	**9,892**	**10,598**	**46,620**
Pass through	**12,743**	**13,041**	**13,136**	**14,178**	**15,321**	**68,418**
Grand Total	**54,559**	**56,612**	**57,462**	**59,270**	**60,283**	**288,186**

10.2. Summary of proposed capex allowances

Table 10.2 summaries our proposed PC3 transmission capex allowances.

Table 10.2: Consortium proposed transmission capex

Category	12/13	13/14	14/15	15/16	16/17	Total
Onshore						
Large I&C Connections	300	400	600	1,000	2,000	4,300
New Towns	815	-	-	-	-	815
Innovation	-	-	-	-	-	-
Refurbishment	23,859	17,027	16,329	17,785	15,646	90,645
Reinforcement	6,574	6,804	3,264	5,728	2,718	25,088
Total Onshore	**31,548**	**24,231**	**20,193**	**24,513**	**20,364**	**120,848**
Interconnector						
Reinforcement	3,100	3,822	3,706	3,511	3,271	17,410
Refurbishment	-	-	-	-	-	-
SWSOS - Future study	1,000	-	-	-	-	1,000
Total Interconnector	**4,100**	**3,822**	**3,706**	**3,511**	**3,271**	**18,410**
Inch						
Refurbishment	675	880	565	560	210	2,890
Total Inch	**675**	**880**	**565**	**560**	**210**	**2,890**
Non-pipe						
IT	4,100	3,350	3,100	2,250	2,200	15,000
Facilities	859	574	692	659	494	3,278
Total non-pipe	**4,959**	**3,924**	**3,792**	**2,909**	**2,694**	**18,278**
Total PC3 capex	**41,282**	**32,857**	**28,256**	**31,493**	**26,539**	**160,426**

ANNEX A: REGULATORY GUIDANCE

This annex summarises the regulatory guidance the CER provided to BGN of how it would review and assess its transmission capex in PC2. The guidance was provided in the final determination paper for the PC2 review.[14]

"For capital expenditure, CER will consider carefully the reasons for any underspends before deciding how to treat them at PR3. CER will take a project by project approach to assessing under and overspends of transmission capex to reflect the nature of the projects involved. This approach recognises that at the time of the determination many of the projects have not yet been scoped out, rather an allowance under certain categories has been made. In general we would expect to adopt the following approach:

- Where the underspend arises because a project has been completed at lower cost than anticipated costs when the control budget is set (assumed to be unanticipated efficiency savings), then BGN would retain the benefits of this underspend for five years from the date of inclusion in the RAB, but the actual rather than forecast capex incurred would be put in the RAB at the end of the five years. With this approach CER is introducing rolling incentives and indicating its expected approach for PR3;
- Where the underspend arises because BGN has not carried out or deferred a project, CER will reach a view on whether this was an efficient deferral, i.e. because demand forecasts had changed. Where the deferral is judged to be efficient BGN will retain the depreciation and return earned for the project in PR2, but no value for the project will be added to the starting RAB for PR3, and it will be for BGN to decide whether to propose the project again in PR3. Where the deferral is judged to be inappropriate by CER, the return and depreciation earned by BGN in PR2 will be clawed back in lower revenues in PR3; and
- Where the overspend arises because a project has been completed at higher cost than anticipated when the control budget is set, CER would not generally expect to remunerate BGN for financing these higher capex costs in PR2, but would consider whether all the actual capex incurred should be included in the starting RAB for PR3. It would be for BGN to demonstrate that the higher actual capex was efficiently incurred, e.g. arising from a competitive tender or a reflection of construction price inflation in Ireland.

Given that transmission projects are generally subject to Section 39A consents. BGN will have an opportunity to flag to CER any cost increases arising from changed specifications or external cost increases from the time of fixing the control budget, which is generally at the time of receipt of construction tenders. As such this will provide an important part of any audit trail for assessing whether financing costs associated with the higher than initially forecast (at the determination) cost are to be recovered in the following period.

[14] CER/07/110 available at: http://www.cer.ie/GetAttachment.aspx?id=9072d8ba-b5d5-49b1-890b-a898fd027def

To illustrate how these rules might apply, consider the following examples from PR1. In each case a rule is linked with an example:

- Lower than anticipated cost – none arose;
- Inefficient/uncontrollable deferral – the proposed NOx related project dependent on the Environmental Operating Licence in Scotland which did not proceed;
- Efficient deferral – the delays to the onshore system reinforcement expenditure; and
- Overspend – the Midleton Upgrade associated with Inch has been allowed as an efficient overspend, although the apparent overspend actually relates to pre-PR1 approved expenditure delayed until the first year of PR1.

The guidance set out here is an indication of how CER expects to approach these issues when setting PR3, but is not binding. However, CER believes that providing this guidance improves certainty for BGN and other market players, thereby improving BGN's incentives to make efficiency savings."