

Northern Ireland Electricity Networks Ltd

Transmission & Distribution 6th Price Control (RP6)

Draft determination

March 2017



About the Utility Regulator

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

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

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

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

Our Mission

Value and sustainability in energy and water.

Our Vision

We will make a difference for consumers by listening, innovating and leading.

Our Values

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

Be a united team

Be collaborative and co-operative

Be professional

Listen and explain

Make a difference

Act with integrity

Abstract

The purpose of this document is to inform stakeholders of our draft determination for the sixth price control for Northern Ireland Electricity Networks Ltd (NIE Networks), known as RP6. We are consulting and seeking feedback from consumers and statutory bodies prior to our publication of our final determination on 28 June 2017. The RP6 price control is due to be effective from 1 October 2017.

Audience

Industry, consumers & statutory bodies.

Consumer impact

NIE Networks has a pivotal role in terms of 'keeping the lights on'. Both the effectiveness and efficiency of NIE Networks are key to industry and domestic consumers. The RP6 price control aims to set an efficient revenue cap to enable NIE Networks to deliver quality outputs that customers need.

NIE Networks' costs are a material and controllable element of electricity tariffs and RP6 investment decisions are expected to underpin improvements in service delivery for consumers.

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1 Executive Summary

Introduction

- 1.1 The purpose of this document is to set out for consultation draft proposals for the NIE Networks RP6 price control.
- 1.2 RP6 is the name given to the price control for the six and half year period from 1 October 2017 onwards.
- 1.3 RP6 sets out the amount that NIE Networks is allowed to build, operate and maintain its transmission and distribution electricity network. It also sets out an incentive regime and sets KPIs and outputs which NIE Networks is expected to deliver over the period. Key decisions for the price control include levels of allowed investment and running costs, efficiency targets, KPIs and rate of return.
- 1.4 This draft determination details the proposals of the Authority (the Utility Regulator, us) with respect to the RP6 price control period. It also considers the expected impact of these proposals on consumers, in particular the expected impact on network charges and consumer bills.
- 1.5 The document is a consultation and we welcome responses. Analysis and dialogue will continue with stakeholders, including the company, and we will provide our final determination on this price control in June 2017 and subsequently consult on licence modifications to bring it into effect by 1 October 2017.

Approach to RP6

- 1.6 We published our RP6 Final Overall Approach document on 22 December 2015. This paper followed an extensive period of consultation and engagement with the company, CCNI, DfE and other stakeholders which included a prolonged consumer engagement exercise.
- 1.7 The conclusion of this set out the aim of the RP6 price control which was to set an efficient revenue cap to enable NIE Networks to deliver quality outputs that customers need.
- 1.8 NIE Networks submitted its RP6 proposals (Business Plan) on 29 June 2016 in line with the requirements we had set out in our Business Plan Template. This process has built on significant effort from Utility Regulator and the company over the last three years to implement a robust reporting framework which aligns with the cost reporting of GB electricity distribution companies.

- 1.9 The NIE Networks proposals have been subject to an extensive query process from Utility Regulator. We have also shared a significant amount of our initial thinking with NIE Networks as part of the process. This has allowed the company to provide further responses on a variety of areas. We have taken these into account in arriving at the draft determination and will further consider all submissions and responses to the draft determination before finalising our RP6 determination.
- 1.10 We have used a number of regulatory tools in arriving at the proposals in this paper.
- 1.11 These include applying econometric techniques to compare NIE Networks to comparable GB electricity distribution companies and determine an efficient level of costs. We have also applied our expertise in assessing investment costs, including working with consultants where appropriate. We have considered regulatory precedent in ensuring the rate of return is set at an efficient level which allows the company to finance its activities and in setting achievable productivity targets for the period.
- 1.12 We have included clear incentive regimes and also set outputs for RP6 which we expect NIE Networks to deliver against. We have identified a number of development objectives which we propose to ensure ongoing progress is made in RP6 to better improve consumer outcomes.

Capital Investment

- 1.13 In its business plan the company identified £383.4m of direct network investment. The company subsequently identified a reduction of £21.1m on this sum as a result of further investigations and engagement. See Table 39: Change in direct network investment from the business plan submission to the draft determination, for a more detailed breakdown.
- 1.14 The draft determination represents a further reduction of £26.1m, a total reduction of £47.2m (12.3%) from the business plan submission net of uncertainty amounts. The majority of reductions are as a result of unit cost adjustments based on RP5 outturn costs. However we have adjusted some of the RP6 volumes based on RP5 run-rates and, in some cases, due to insufficient justification.
- 1.15 The draft determination provides allowances for £336m of direct network investment to maintain and reinforce the network in the RP6 period. In addition to this we have included mechanisms to introduce allowances for the construction of the north south interconnector and other transmission capacity growth projects which we forecast at £200m of investment.
- 1.16 Allowances for total network investment amount to £662m across RP6, including both direct network investment, metering, ICT as well as IMF&T.

Efficiencies in operational expenditure

- 1.17 We are proposing to reduce the company forecast for RP6 Indirects and IMF&T by just over 10% as a result of detailed top-down econometric modelling. This is equivalent to just under a £7m per annum difference between us and the company's RP6 Business Plan submission. This results from a 2.0% efficiency adjustment to the 2015/16 base year operational costs which is then rolled forward across the RP6 period.
- 1.18 Our econometric modelling is taken from extensive model testing, selection and our eventual triangulation approach. The latter ensures we have taken a conservative view of NIE Networks' efficiency gap to the upper quartile comparator companies in GB.
- 1.19 Whilst the larger part of the difference is due to our disallowing company claims for additional Indirects and IMF&T funding for ESQCR and Innovation programmes (which we view as already allowed for in our upper quartile efficient base year adjustment) the fact we have set efficiencies at the upper quartile leaves room for NIE Networks to out-perform the RP6 regulatory contract.
- 1.20 Out-performance remains incentivised under the same arrangements established by the Competition Commission (CC) at RP5, namely the 50:50 sharing incentive (between the consumer and the company).
- 1.21 Incentivised out-performance during RP6 will, having revealed further efficiencies, be taken into account when setting RP7 efficient costs and be included as a reduction to the company's cost base going forward.
- 1.22 We consider we have set a challenging but achievable target for NIE Networks. Although 2% catch-up is a relatively small percentage figure, it should be noted that this target is in conjunction with a 1.0% per annum productivity assumption (included within our frontier shift calculation).

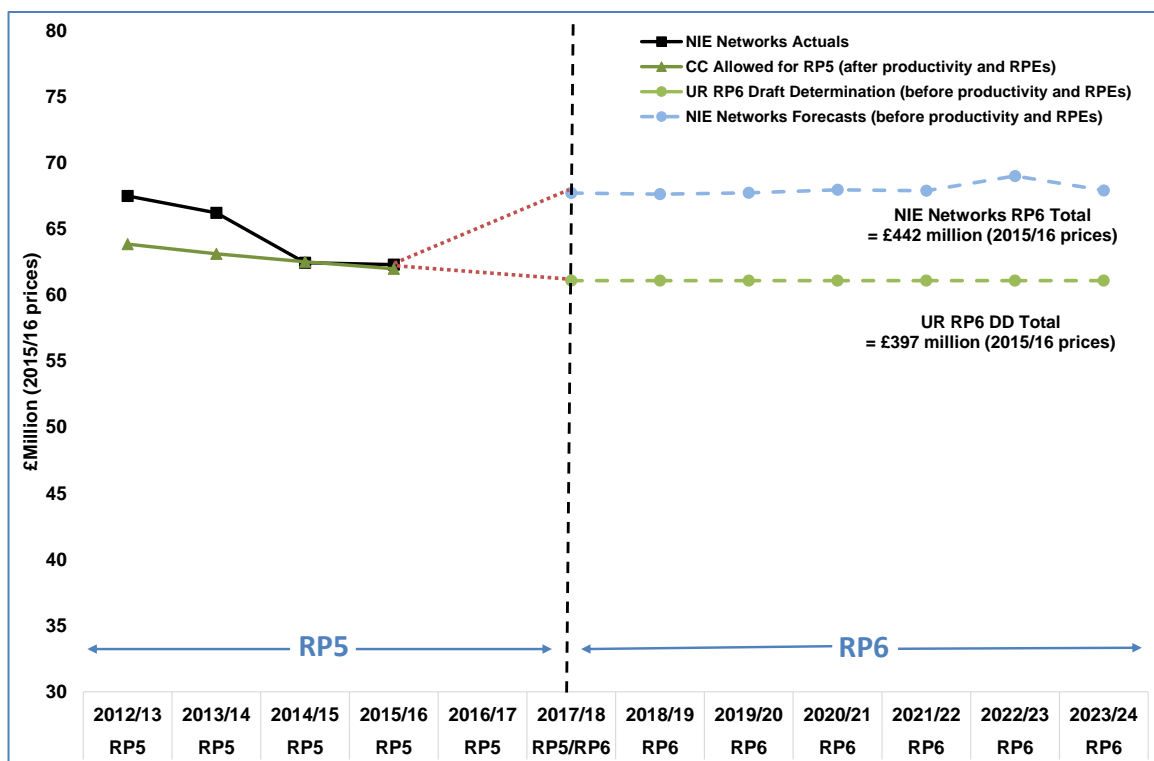


Figure 1: Draft determination IMF&T and Indirects

RP6 Outputs and KPIs

1.23 Various outputs and KPIs are included within this draft determination for consultation including:

- **new Reliability Incentive** concerning Customer Minutes Lost (CML) – which incentivises the company to reduce the amount of time customers suffer from supply interruptions;
- **new Substitution Mechanism** concerning capital investment, to ensure any deferral of planned projects is efficient, alongside annual reporting of progress with the company's capital plan. The mechanism and reporting thereof will be subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan);
- **ongoing consumer and stakeholder engagement** - subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan);
- **Guaranteed Standards of Service (GSS), including connections** – subject to ongoing reporting;
- **Asset health and Load indices** – for development during RP6;

- **Worst served customers (WSC)** - subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan);
- **new customer advocacy and survey metrics** - subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan) AND subject to developmental timeframe of year 3 of RP6.

Financial Aspects

- 1.24 We propose to apply a rate of return of 3.29% at the outset of the RP6 period. Our starting rate of return is lower than the figure put forward by the company of 4.1% because we have:
- aligned NIE Networks' cost of equity to be no higher than Ofgem's estimated RIIO-ED1 cost of equity;
 - updated NIE Networks' February 2016 cost of debt calculation for the latest market evidence; and
 - used the OBR's inflation forecast to translate the forecast nominal cost of debt into its real, RPI-stripped equivalent, in preference to NIE Networks' lower inflation forecast.
- 1.25 This return may subsequently be adjusted up or down within period in light of any changes in market interest rates when NIE Networks raises new debt.
- 1.26 In assessing whether our draft determination leaves NIE Networks in a position where it will be able to finance its activities during the RP6 period, we have considered the ability that the business will have to utilise both equity and debt finance.
- 1.27 Our assessment is that NIE Networks is capable of financing itself through the RP6 period with a prudent mix of equity and debt capital.

RP6 Tariffs and Consumer Impact

- 1.28 In 2015/16 total network charges accounted for approximately 21% of the final electricity bill. This percentage varies each year depending on electricity wholesale prices and other costs which make up the final bill, such as system operator costs and supplier costs.
- 1.29 The percentage of the final electricity bill also varies depending on the customer group. Network charges account for approximately 25% of the final bill for domestic and 22% for small business customers. For large energy users and small to medium enterprise customers, network charges account for between 5% and 18% of the final electricity bill.

- 1.30 Table 1 shows a comparison of NIE Networks' proposed average network charges at the end of RP6 (2023/24) compared to the Utility Regulator's proposed average network charges at the end of RP6 (2023/24). The current average network charge for a domestic customer is £130 per annum.

Customer group	Number of customers	NIE proposed Average network charges at the end of RP6			UR proposed Average network charges at the end of RP6		
		D £/annum	T £/annum	Total £/annum	D £/annum	T £/annum	Total £/annum
Domestic	790,000	123	17	140	106	15	121
Small business	65,000	579	83	662	498	73	571
SME > 70k VA	5,000	8,807	1,485	10,292	7,570	1,303	8,873
LV & HV LEU > 1MW	172	58,358	19,667	78,025	50,158	17,257	67,415
33kV LEU > 1 MW	18	103,902	91,441	195,343	89,302	80,236	169,538

Table 1: RP6 NIE Transmission and Distribution forecast average network charges

- 1.31 In summary, our proposals would result in a small decrease over the six years of RP6 in the network charges paid by consumers. By 2023/24 this reduction would be £19 per annum compared to the NIE Networks proposals and £9 per annum compared to the current tariff equating to c.1.7% on the total retail bill. The comparable figures for larger customers will be significantly higher with a reduction in current tariffs of up to £10k for the very largest by 2023/24. It is important to remember that these figures all exclude RPI inflation and costs associated with transmission network capacity growth projects which are uncertain. RPI inflation will be applied to NIE Transmission and Distribution allowed revenue each year.

RP6 Revenue Impact

- 1.32 Table 2 shows the impact on overall revenue across the RP6 period as the draft determination proposes to reduce the company RP6 submission by just under 11%.

	NIE Networks Proposal	Utility Regulator draft determination
	£m	£m
Distribution	1,284.3	1,145.8
Transmission	278.2	248.1
Total	1,562.5	1,393.9

Table 2: RP6 effect on NIE Networks revenue

1.33 The reduction represents the net impact from the following draft determination proposals for consultation (non exhaustive list of more material assumptions):

- Proposed rate of return of 3.29% compared to NIE Networks' 4.1%;
- 2.0% efficiency adjustment to Indirects and Inspections, Maintenance, Faults & Tree-cutting (IMF&T) or base operational expenditure, rolled forward across the RP6 period;
- Just under a 13% reduction to direct network investment in capital projects and programmes, across the RP6 period;
- a productivity assumption of 1% per annum, applied to both operation and capital investment expenditure across the RP6 period, and real price effects;
- a detailed bottom-up assessment of NIE Networks' IT proposals by Gemserv consulting, reducing the company's submission by just over 11% across RP6;
- various other detailed assessments including pensions, severe weather allowance and business rates.

Next Steps

1.34 Responses to this consultation should be received on or before 1700 on Friday 19th May 2017.

1.35 We will consider our final determination in light of the responses received to our consultation. We will be holding a workshop on 28 April 2017 at 1000 in our offices and all interested stakeholders are welcome.

1.36 We aim to publish our final determination on 28 June 2017 and will account for our findings and consideration of the consultation responses received as part of the determination.

1.37 The publication of the RP6 final determination will be accompanied by a consultation on related licence modifications to bring the RP6 price control into effect from 1 October 2017.

2 Introduction

Purpose of the document

2

- 2.1 On 22 December 2015 we published our final approach document to RP6 detailing our overall approach to the next price control for Northern Ireland Electricity Networks Ltd (NIE Networks). This sixth price control is referred to as RP6.
- 2.2 The purpose of this document is to provide our draft determination of RP6 for public consultation and to invite consultation responses across the following 8-week consultation and further engagement period, prior to our final determination on 28 June 2017.
- 2.3 This document sets out our draft determination for consultation as follows:
- Section 1 contains our Executive Summary
 - Section 2 introduces the reader to the reasons for this document; background; RP6 approach and duration; NIE Networks' submission and the subsequent RP6 Business Plan Query process
 - Section 3 provides a high level review of NIE Networks' progress to date with regard their last price control or RP5
 - Section 4 focuses upon the proposed RP6 regulatory contract with regards outcomes and outputs for consumers and any new KPIs we expect to begin monitoring NIE Networks during RP6
 - Section 5 details our approach to operating costs and efficiencies where we benchmark the efficient level of expenditure across IMF&T and Indirect costs across RP6
 - Section 6 details our approach to and determination of other operating costs
 - Section 7 provides a high level description of our assessment of NIE Networks' ICT expenditure for RP6, as undertaken by Gemserv consultancy
 - Section 8 details our approach to and determination of the company pensions deficit repair
 - Section 9 details our approach to network investment benchmarking, the roll-forward of any deferred capital expenditure under RP5 into RP6 and other optional investment planning (including innovation funding)

- Section 10 details our approach to frontier shift, including real price effects (RPEs) and productivity assumptions across both operational and capital expenditure
- Section 11 details market operations and other activities, and our approach to setting an efficient level of expenditure for these costs
- Sections 12 details various financial aspects of RP6, including the weighted average cost of capital (WACC) and finance-ability
- Section 13 details the various uncertainty mechanisms both proposed by the company and our draft determination decisions for consultation
- Section 14 details the various incentive mechanisms both proposed by the company and our draft determination decisions for consultation
- Section 15 details and future reporting requirements for RP6, to enable our annual cost and performance reporting of NIE Networks' progress against its regulatory contract
- Section 16 focuses on any RP6 implications for NIE Networks' licence and the various licence modifications we shall progress with the company in advance of the more formal Licence Modifications and Appeals (LMA) process
- Section 17 details the next steps for this RP6 draft determination consultation, including the deadline for and the means by which any respondent might submit their feedback
- Various Technical Annexes are also listed, including web links, to the various sections above

2.4 As with our previous RP6 Approach document and more recent amendment to the RP6 timetable, a further stakeholder workshop is scheduled for 28 April 2017. This is in advance of the RP6 draft determination consultation deadline of Friday 19 May 2017.

Background

2.5 The role of the Utility Regulator is determined under legislation and its statutory principal objective in relation to electricity matters is:

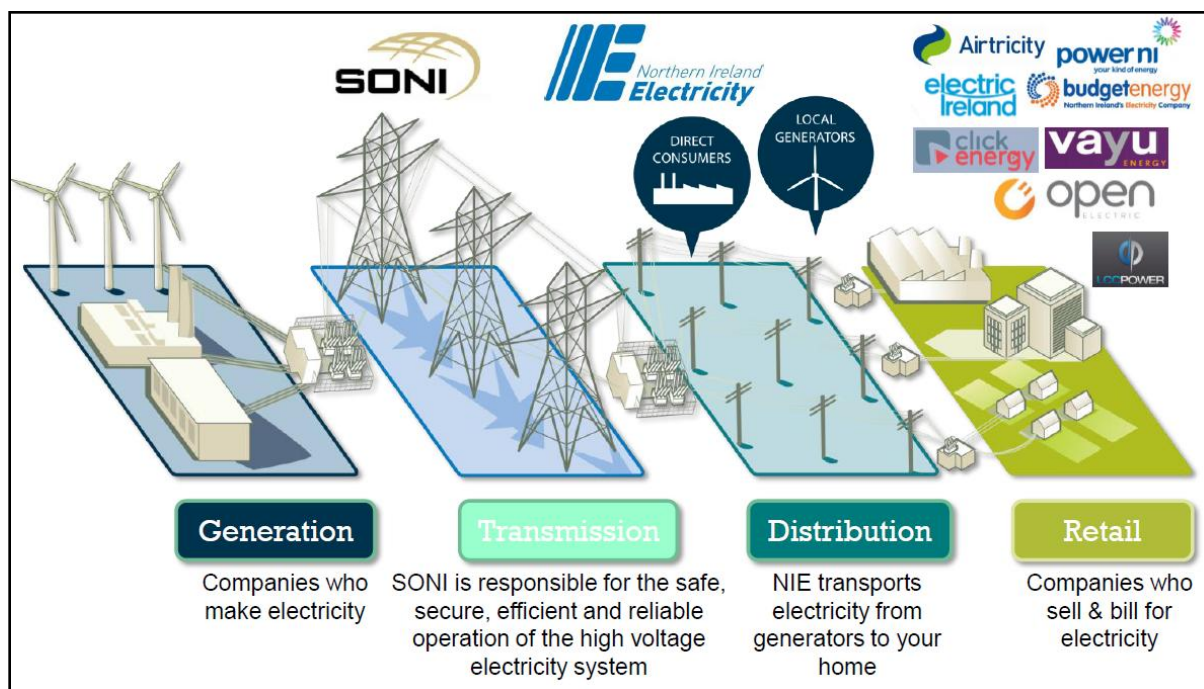
“To protect the interests of electricity consumers in Northern Ireland, wherever appropriate by promoting effective competition between persons engaged in or in commercial activities connected with the generation, transmission or supply of electricity.”

2.6 We are a non-ministerial government department, accountable to the NI Assembly.

2.7 In carrying out its functions, the Utility Regulator should act in the manner best calculated to further the principal objective, having regard to:

- i. The need to secure that all reasonable demands for electricity are met; and
 - ii. The need to secure that licence holders are able to finance the activities which are the subject of obligations imposed under NI energy law.
- 2.8 The Authority is required to carry out its respective electricity functions in the manner which it considers is best calculated:
 - I. to promote the efficient use of electricity and efficiency and economy on the part of persons authorised by licences or exemptions to supply, distribute or participate in the transmission of electricity;
 - II. to protect the public from dangers arising from the generation, transmission, distribution or supply of electricity;
 - III. to secure a diverse, viable and environmentally sustainable long-term energy supply;
 - IV. to promote research into, and the development and use of, new techniques by or on behalf of persons authorised by a licence to generate, supply, distribute or participate in the transmission of electricity; and
 - V. to secure the establishment and maintenance of machinery for promoting the health and safety of persons employed in the generation, transmission, distribution or supply of electricity.
- 2.9 In performing the above duties, regard shall also be had to the interests of groups of vulnerable consumers in Northern Ireland, comprising the disabled and chronically sick, pensioners, low income consumers and residents of rural areas.
- 2.10 In carrying out its electricity functions, the Utility Regulator must not discriminate between persons whose activities include generating, supplying or transmitting electricity.
- 2.11 We set overall limits on how network prices can rise, or are required to fall, through a process called price controls.
- 2.12 The price control process must therefore start with a business plan (including actual data for previous years), as submitted by NIE Networks, setting out their proposals for costs going forward. The information submitted will be scrutinised by us. In doing so, we seek to ensure NIE Networks deliver best value for money for all consumers.
- 2.13 Our approach is based on best practice regulation of natural monopolies. Our task essentially consists of implementing a framework within which, in return for providing monopoly services to an acceptable quality, the company receives a reasonable assurance of a revenue stream in future years that will cover its efficient costs and ensure fairness for the consumer.

- 2.14 Due to its natural monopoly position, the amount of revenue which NIE Networks earns is subject to a price control. This is set by the Utility Regulator following consultation with stakeholders and the wider public.
- 2.15 The electricity network is made up of a transmission and a distribution component. NIE Networks has responsibility for the running of its distribution system. However due to EU requirements for the independence of certain activities, NIE Networks shares the responsibilities of running its transmission network.
- 2.16 Transmission related responsibilities are split between NIE Networks and a separate body; the System Operator for Northern Ireland (SONI). NIE Networks' own, finance and carry out the necessary maintenance and development of the transmission network.
- 2.17 SONI is responsible for the day to day operation of the transmission system. That is, SONI directs the flows of electricity over the transmission network from generators. In doing this they are continually matching the supply of and demand for power across Northern Ireland. SONI is also responsible for connections to the transmission system. More recently SONI have become responsible for transmission system planning.
- 2.18 The various activities and responsibilities within the electricity industry in Northern Ireland are illustrated below. This split in responsibilities, particularly between NIE Networks and SONI, should be kept in mind when reading this document and is highlighted below in diagrammatic representation.



RP6 Approach

- 2.19 On 23 September 2015 we published a RP6 Overall Approach document for consultation on our intended overall approach to the next price control for Northern Ireland Electricity Networks Ltd (NIE Networks).
- 2.20 The RP6 price control aims to set an efficient revenue cap to enable NIE Networks to deliver quality outputs that customers need. NIE Networks' costs are a material and controllable element of electricity tariffs and RP6 investment decisions are expected to underpin improvements in service delivery for consumers.
- 2.21 We published our RP6 Final Overall Approach document on 22 December 2015. The responses to our September 2015 consultation were published along with our final approach. We set out the main areas of comment from the consultation responses and made some adjustments to our approach in response to consultation feedback.
- 2.22 In particular we included additional detail or confirmed and restated our original approach. Overall we did not consider our changes materially altered our approach.
- 2.23 Various stakeholder workshops occurred during our draft determination process:
- a draft RP6 Overall Approach for consultation workshop on 8 October 2015; plus
 - two stakeholder planning workshops with wider stakeholders and renewables representatives on 11 and 12 January 2017. These included engagement with stakeholders over many of the key issues for the RP6 period in the context of NIE Networks' RP6 Business Plan submission.
- 2.24 The revision to our original timetable¹ was the result of both lessons learned from the closest network price control to RP6 in the form of GD17, as well as in light of the company's substantial [RP6 Business Plan submissions](#). Our aim was to progress RP6 by building on the substantive engagement with the company and stakeholders alike and further engagement with stakeholders is planned for the 8-week consultation period² between draft and final determinations.
- 2.25 We are grateful to all those that attended the various workshops, their contributions on the day and the various consultation responses we received from organisational representatives alongside other bilateral engagement meetings.
- 2.26 The revised RP6 timeline as presented to stakeholders, also included within our website, is at Table 1 below:

¹ The revised timetable included the addition of a staged approach to Licence modifications as required under new legislation.

² The effective start date of the RP6 price control remains 1 October 2017 and will build on various consultation stages to the determination process, including the new more consumer focused 8-week formal consultation between draft and final determinations (as specified within the [Fresh Start Agreement](#) which introduced a new 8-week maximum consultation period for policy, starting from May Elections 2016 onward).

RP6 Key Stages	Revised RP6 Timetable (8-week consultation)
Approach Document	
<i>Initiate working level meetings - scoping phase</i>	13 February 2015
<i>Close off scoping</i>	18 August 2015
<i>Publish RP6 Approach Document for consultation</i>	23 September 2015
<i>Stakeholder Workshop</i>	8 October 2015
<i>Publish Approach Document</i>	18 November 2015
RP6 Business Plan	
<i>Initiate working level meetings – clarify the Approach</i>	18 November 2015
<i>Close off clarifications</i>	16 December 2015
<i>Issue Business Plan Information Requirements to NIE Networks</i>	20 January 2016
<i>Business Plan Information Requirements formal query process</i>	Jan/February 2016
<i>Close queries and end query process</i>	17 February 2016
<i>Business Plan submission from NIE Networks</i>	29 June 2016
Draft Determination	
<i>Business Plan formal query process</i>	July 2016 to February 2017
<i>Publish Draft Determination for consultation</i>	24 March 2017
Final Determination	
<i>Draft Determination consultation closes</i>	19 May 2017
<i>Publish Final Determination</i>	28 June 2017
<i>Article 14(2) Stage 1 Licence Modification Notice</i>	28 June 2017
<i>x28 day min period for Licence Modification Notice Period ends</i>	27 July 2017
<i>Due consideration of responses to proposed Licence Modification</i>	28 July to 3 August 2017
<i>Article 14(8) Stage 2 Notice of decision on how to proceed published</i>	4 August 2017
<i>x56 day minimum period from publication date of decision to proceed ends</i>	29 September 2017
Effective start date for RP6	1 October 2017

Table 3: Revised RP6 timetable

Duration

- 2.27 In our RP6 Final Overall Approach document we stated we believed a 6-year duration would strike the right balance between providing sufficient certainty for NIE Networks of the strong incentive to reduce costs whilst not exposing the company or consumers to undue risk.
- 2.28 A re-alignment of regulatory and RIGs/NIE Networks' financial reporting years to run simultaneously April 20XX to 31 March 20XY was possible if we extended RP6 to 6½ years. This option would then remove the requirement for NIE Networks and us to pro rata between years for simple differences in tariff (accounting) and price control years as we monitor the company's progress during the RP6 period³.
- 2.29 We are adopting a once only, 6½ years duration for the RP6 price control period.

³ If NIE Networks accepts our determination we shall require it to work with us to produce a Monitoring Plan setting out its programme for delivery over the RP6 period. The RP6 Monitoring Plan will need to be fully consistent with our determination and shall supersede its RP6 Business Plan. In so doing, we shall provide customers, stakeholders and ourselves with the means of assessing progress during the control period.

RP6 Business Plan submission

- 2.30 The company at RP6 submitted a comprehensive Business Plan, addressing various requirements as laid out by the Utility Regulator in our Business Plan Templates (BPT) and associated information requirements:
- BPT Overarching Guidance which included a brief set of instructions for the RP6 Business Plan submission alongside our requirement for a public facing Executive Summary
 - BPT Guidance Notes, similar to those employed across the existing RP5 Regulatory Information Guidance (RIGs)
 - BPT Reporting Workbooks, where NIE Networks were expected to populate their historical and forecast projections alongside other data in support of their RP6 Business Plan
 - BPT Commentaries, where NIE Networks had the option to populate in free text any special considerations they might have wished to draw to the attention of the Utility Regulator when using their data submission
 - BPT Assurance Workbooks (if deemed necessary by the teams responsible for individuals sections⁴)
 - BPT Glossary Appendix, including any additional definitions of terms to those already applying to the current RP5 RIGs
- 2.31 The company's web-based [RP6 Document Library](#) contains both their main report business plan, executive summary and various supporting reports:
- Transform Model – a N Ireland specific model evaluating options for low carbon technologies
 - Domestic consumers willingness to pay for network improvements (Perceptive Insight Market Research)
 - Quantitative research with non-domestic consumers (Perceptive Insight Market Research and Queen's University, Belfast)
 - Empowering consumers, beginning a conversation on consumer priorities for the N Ireland electricity network - summary & recommendations from consumer engagement
 - Have your say on the future of the electricity network, 2017-2024 - proposed investment options for discussion with consumers

⁴ Apart from the BPT Pensions (for which specific Data Assurance requirements as detailed in the BPT Pensions Guidance Notes apply) no formal data assurance of the RP6 business plan submission was required. Instead we expected NIE Networks to include their best estimate of costs and activities across the RP6 price control period and to be held to account for their delivery of the eventual RP6 regulatory contract of outcomes, outputs and KPIs.

- The way forward, an outline of NIE Networks' investment plans, 2017-2024 - outline of the proposed RP6 core & optional business plan

2.32 In addition, the company submitted:

- **a suite of BPT documents** comprising completed Excel spreadsheets and commentary Word documents, as provided by the Utility Regulator for completion⁵. These fulfilled our requirements on:
 - BPT Reporting Workbooks where NIE Networks populated spreadsheets with their historical and forecast projections alongside other data in support of the RP6 Business Plan; and
 - BPT Commentary Templates where NIE Networks had the option to populate in free text any special considerations they may have wished to draw to the attention of the Utility Regulator when using their data submission.
- **various supporting reports and supplemental documents** to the suite of BPT documents in fulfilment of our requirement to provide supporting material, consistent with the information in the suite of BPT documents, the RP6 Main Report and Executive Summary.

2.33 In total, the RP6 submission files totalled over 270MB worth of data, spreadsheets, reports and annexes.

RP6 Business Plan Query Process

2.34 As with any network price control the Utility Regulator established a query process to lodge new queries with NIE Networks on a weekly basis, with the expectation of a x10 working day turnaround for response by the company.

2.35 Given the very comprehensive submission from the company and the degree of positive, working level engagement between respective teams across:

- pensions;
- benchmarking;
- network investment;
- innovation;
- outputs, incentives and uncertainty; as well as
- all the various financial aspects to RP6,

⁵ The various BPT requirements were refined through a very positive, working level engagement process with the company. Draft BPTs were discussed, alongside our minded to approaches to key RP6 workstreams as documented within our draft and final RP6 Overall Approach documents.

more than three hundred individual queries were raised across the 8-month duration the team examined, assessed and tested the RP6 Business Plan submission.

- 2.36 The query process also augmented the positive working level engagement that took place throughout the draft determination stage. Important and material issues discussed in meetings were recorded formally as queries for NIE Networks consideration and subsequent submission to the Utility Regulator.
- 2.37 The regular engagement meetings also allowed both NIE Networks and ourself to identify material differences of opinion and/or approach in the lead up to the draft determination publication. This has meant we have adjusted our approach in a number of important workstreams, including benchmarking efficiencies of Indirects and IMF&T, our bottom-up assessment of the company's ask regarding both ICT and innovation investment, as well as wider network investment and pensions considerations.
- 2.38 The decision to move to the 8-week consultation period is set out in the Fresh Start Agreement (FSA), clause 65 with Appendix F6 - Draft Guidelines on Good Practice in Public Consultation Engagement recommending, amongst other things, "early and continuous engagement - pre consultation,...of the issues through a dialogue with stakeholders prior to policy decisions being more formally considered".
- 2.39 Whilst our formal 8-week consultation period for the draft determination is somewhat shorter than the 12 weeks that would previously have applied, our aim over the successive months after the company submitted its RP6 Business Plan has been to engage in as transparent a manner as possible to ensure our formal consultation benefits from early, pre-consultation engagement envisaged under the FSA.

3 RP5 Delivery

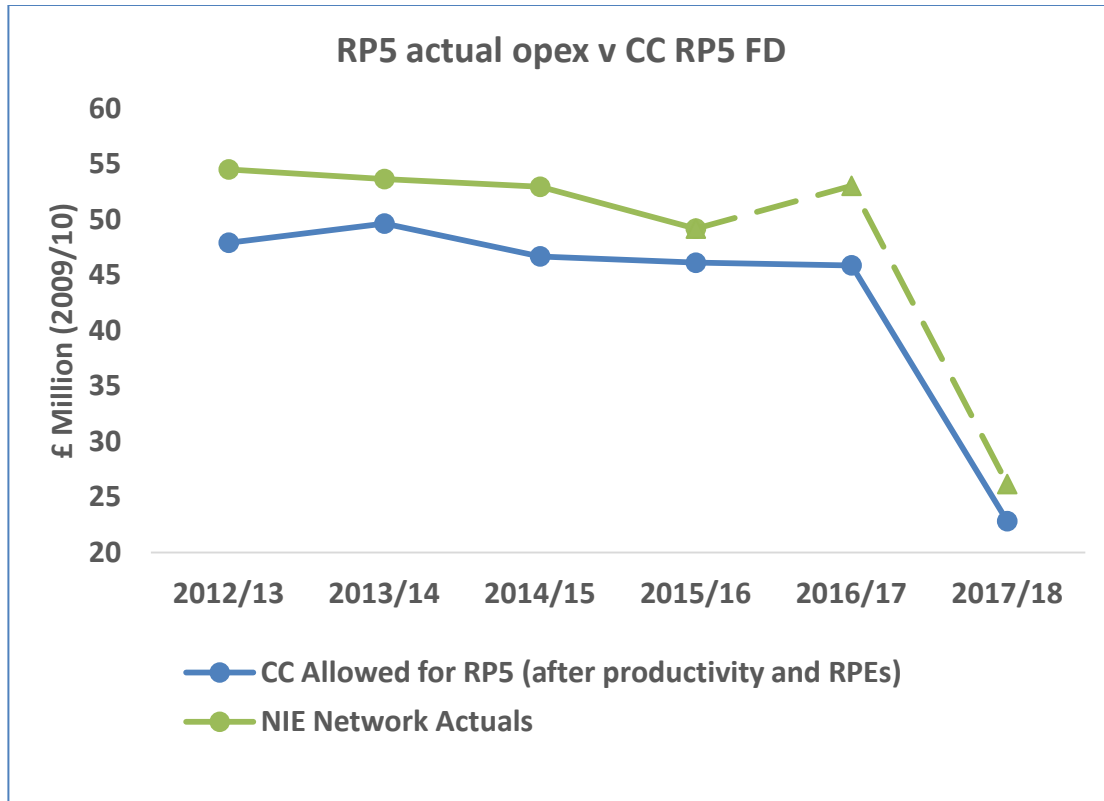
Introduction

3

- 3.1 In RP5 the previous Competition Commission (now CMA) defined the key outputs including allowances and investment outputs.
- 3.2 To enable a better understanding of delivery, we compare the allowances set against actual performance.
- 3.3 Reflection on company performance against previous allowances, informs our view going forward and can highlight important or emerging issues for consumers in RP6.
- 3.4 We will now examine the main outputs of RP5, with a brief analysis of differences between allowances and outputs. By its nature this analysis is very high level as RP5 is incomplete. We will provide a full review of RP5 in our cost reporting framework once we have received full accounts for the period. We expect this will be in 2018.

Opex Costs

- 3.5 The term 'Opex Costs' is used to distinguish the ongoing running costs of NIE Networks electricity system. For example Opex Costs include: maintenance of poles and wires, business rates, meter reading and costs of supporting retail market opening.
- 3.6 Compared to the CC's Final Determination, NIE Networks have spent more than forecast for each of the four years ending 31st March 2013, 2014, 2015 and 2016. The main areas for the over-spending are: Inspections costs; Maintenance costs; Fault costs; and Indirect costs.
- 3.7 Costs in relation to NIE Networks expenditure on Inspections, maintenance, faults and tree cutting (IMF & T) are discussed in detail in Chapter 5: IMF & T and Indirects.
- 3.8 For the four years ending 31 March 2016, NIE Networks have spent circa £20m more than the CC RP5 final determination allowances.



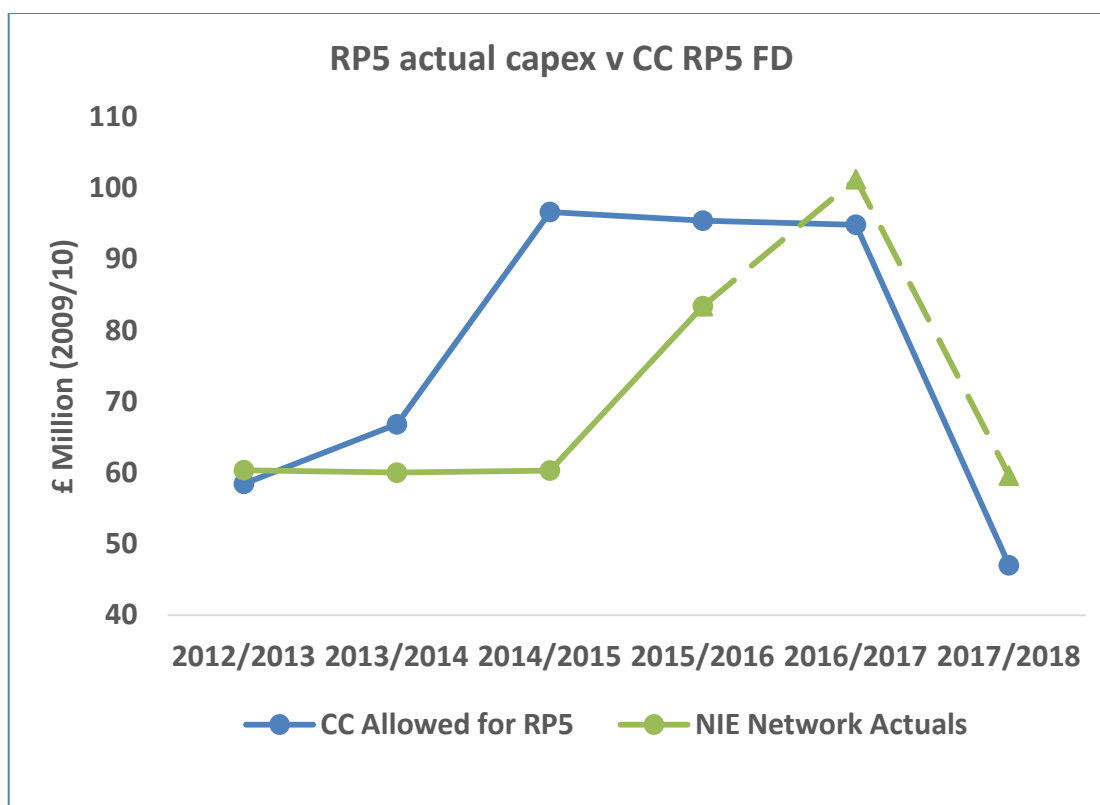
Note 1: 2016/17 and 2017/18 NIE actuals are NIE forecast costs

Note 2: 2017/18 costs based on half year data as RP5 finishes end September 2017

Figure 2: NIE Networks actual RP5 opex v CC RP5 opex final determination (2009/10 prices)

Capex Costs

- 3.9 The term 'Capex Costs' is used to refer to new assets installed on NIE Networks electricity system. For example Capex Costs include: the purchase and installation of new assets; replacing old assets; and connecting customers to the electricity network.
- 3.10 When compared to the CC's Final Determination NIE Networks has spent roughly £53m less on capex up to the end of March 2016. Most of this underspend occurred in the 2014/2015 year.
- 3.11 NIE Networks has explained the main reasons for the under-spend as; phasing of projects; and the targeting of lighter circuits pending the CC's Final Determination.



Note 1: 2016/17 and 2017/18 NIE actuals are NIE forecast costs

Note 2: 2017/18 costs based on half year data as RP5 finishes end September 2017

Figure 3: NIE Networks actual RP5 capex v CC RP5 capex final determination (2009/10 prices)

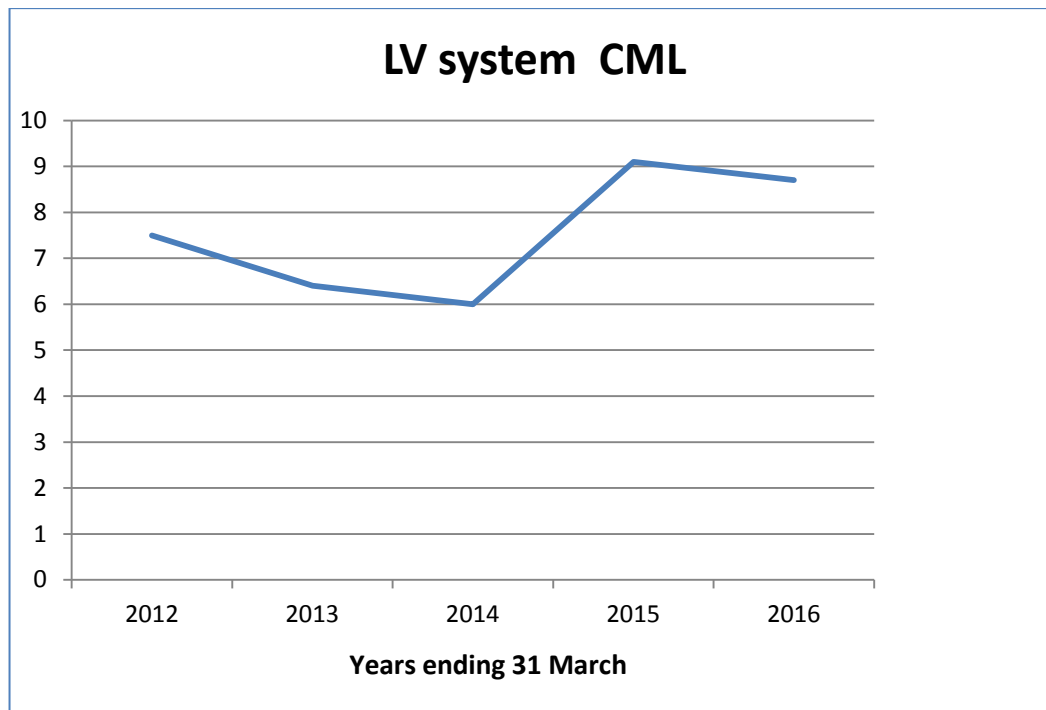
RP5 Output delivery and performance (outputs and outcomes)

Introduction

- 3.12 It is important to consider how the electricity system is performing, in order to give a more meaningful picture of efficient investment.
- 3.13 One of the ways of assessing the performance of the electricity system is to monitor frequency and duration of interruptions to electricity supply. The frequency of interruptions is captured in a metric called Customer Interruptions (CI), and the duration of interruptions is captured in a metric called Customers Minutes Lost (CML).
- 3.14 Although the CC did not set targets for CI or CML, for the purposes of this section we focus on the duration of interruptions as captured in the CML metric.

Customer Minutes Lost

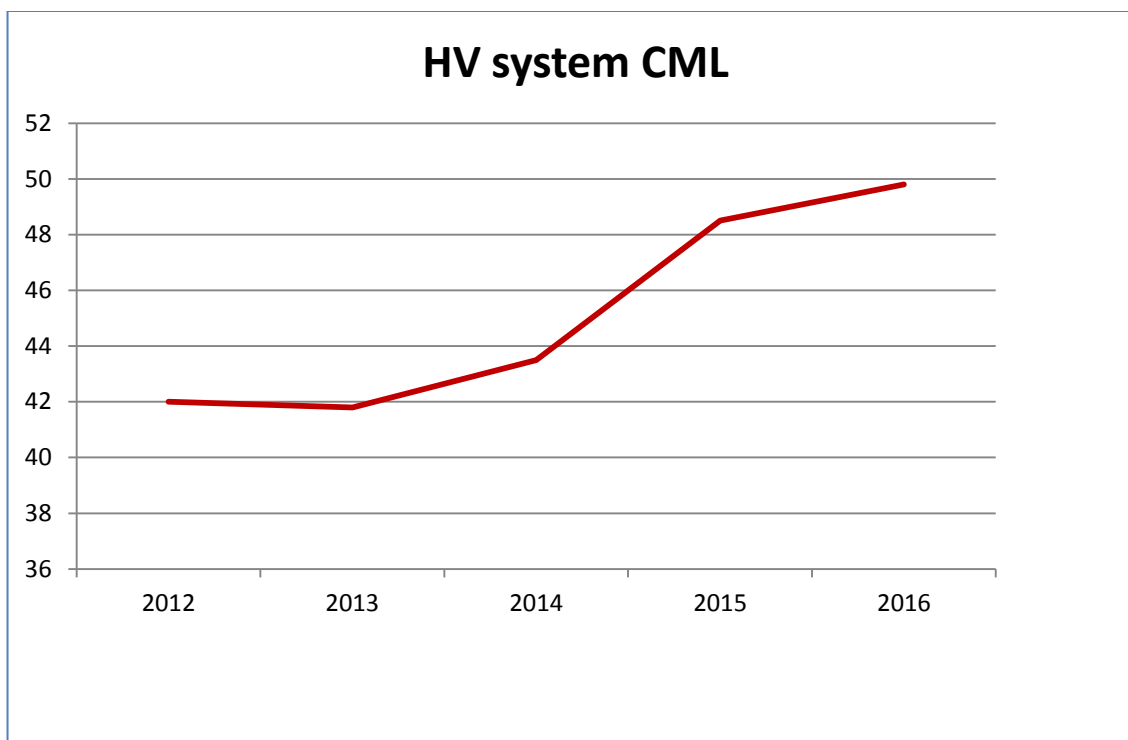
- 3.15 CML is the average minutes lost per customer, per year, where an interruption to electricity supply lasts for three minutes or longer.
- 3.16 The Customer (or Supply) Minutes Lost is a measure of reliability as it takes into account the amount of interruptions and the length of those interruptions. A network which is inadequately maintained will degrade and, after a time, have more frequent and lengthy faults which will be reflected in CML performance.
- 3.17 A degrading trend should not be assumed in the short term due to annual fluctuations in fault data and therefore it would not be prudent to give weight to the CML data at this time. We will, however, monitor the CML trend annually in order to identify potential links between under-investment and degrading network performance.
- 3.18 The Low Voltage system feeds domestic and commercial loads. Performance over the RP5 period is shown in figure 4 below.



Note 1: measured as an average, per customer, per year

Figure 4: NIE Networks Customer Minutes Lost (CML) 2012 to 2016 on Low Voltage System

- 3.19 The High Voltage system feeds some industrial consumers and the majority of secondary substation loads. Performance over the RP5 period is shown in figure 5 below.



Note 1: measured as an average, per customer, per year

Figure 5: NIE Networks Customer Minutes Lost (CML) 2012 to 2016 on High Voltage System

Future Reporting

- 3.20 We noted in the RP5 approach document that although the CC did not set targets for CI or CML, for RP5, we intended to consider again these measures for the following price control (RP6). We have given target setting for CI and CML further consideration and proposed a reliability incentive scheme and this is discussed further in RP6 Outcomes, Outputs & KPIs.
- 3.21 We expect to review the performance of NIE Networks for the entire RP5 period and produce a Cost and Performance report towards the end of 2018. We expect that the report will review NIE Networks' performance on opex, capex and outputs for the RP5 period.
- 3.22 We plan after the review of RP5, to produce an Annual Cost and Performance report each year for RP6, to monitor progress of performance against regulatory allowances, to enable better transparency for all stakeholders. As RP6 commences mid way through the normal reporting cycle, which is normally at the end of March, we will need to consider whether it is appropriate to review and report on either a ½ year or 1 ½ years performance.

Application of D3 (deferral) mechanism

- 3.23 Figure 3 shows the variance between capital investment in RP5 and the capital allowances included in the Competition Commission's final determination for RP5 in 2009/10 prices.
- 3.24 Up to 2015/16, the company had invested £53m less capital (in 2009/10 prices) than the RP5 final determination allowed. The total capital invested in RP5 is projected to be £32m less than allowed in the final determination.
- 3.25 The capital allowances set by the Competition Commission in the RP5 final determination were ex-ante allowances. The company were incentivised to under-spend its allowances through the 50/50 cost risk sharing mechanism, which shares out-performance between the company and consumers. In addition, the Competition Commission specified measures to protect consumers from the deferral of planned network investment (the D3 mechanism). The intention is that there should be no double funding of any deferred network investment.
- 3.26 The application of the D3 mechanism is limited to a category of 'planned network investment' which are those activities for which the Competition Commission identified a specific output or volume of outputs in the RP5 final determination, a total of £192m (42%) of the capital allowances.
- 3.27 The company provided a forecast of network investment expenditure and outputs in its business plan submission which indicated that it planned to deliver all the planned outputs for RP6. In view of this we have not included any adjustment for deferred investment (pre-funded costs) in this draft determination.
- 3.28 However, this assessment was made on a report based on actual expenditure for the four year period up to 2015/16 and estimates for the remaining one and a half years of RP5. This report indicated that approximately 40% of planned network investment in RP5 would be delivered in the last year and a half. In view of this:
- i) We expect the company to provide updated information on the RP5 out-turn when it provides its response to the draft determination. This should include an update of the RP5 Out-turn report and the Network Investment RIGS to reflect actual planned network investment expenditure and outputs up to the end of 2016/17 and current forecasts for the last half year of RP5.
 - ii) We will update our assessment of deferral and any adjustment for pre-funded costs in the final determination.
 - iii) We will review the out-turn of planned network investment and volumes for the RP5 period when final information is available. Any shortfall in out-turn volumes will be taken into account in the use of any 'no double-recovery' principle in setting the subsequent price control

- 3.29 The savings in planned network investment achieved by the company in RP5 form the basis for our determination of unit rates for the same activities in RP6.

4 RP6 Outcomes, Outputs & KPIs

Introduction

4

- 4.1 Of the outputs (n=55) identified by the company, alongside various other incentives and uncertainty mechanisms referenced within its RP6 Business Plan and annexes, we examined each using our experience of setting KPIs, targets and monitoring company performance in other price controls.
- 4.2 In applying best regulatory principles to RP6 we already have set out our intention to establish an RP6 Monitoring Plan, setting out a programme for delivery over the RP6 period by NIE Networks. The RP6 Monitoring Plan will be fully consistent with our determination and shall supersede the company's RP6 Business Plan.
- 4.3 Our annual cost and performance reporting of NIE Networks' progress in meeting its RP6 regulatory contract, targets and KPIs, for example, shall apply the strong, local reputational incentives upon NIE Networks in the same manner as we have developed our model of regulation for NI Water.
- 4.4 We set out below our views on the Outputs, KPIs and Development Objectives for RP6 and will continue to develop and add more detail to these as we progress to the final determination.

Ongoing consumer and stakeholder engagement

- 4.5 The company included various improvements (incremental and discrete) to customer service across RP6 including:
 - telephone call response rates and time to response (including use of HVCA)
 - zero defaults of GSS and zero failures on OSS
 - priority information service for customers already on the Critical Care Register
 - reduce complaint numbers and respond within target time periods
 - zero complaints escalated to the CCNI
 - prompt response to social media, written enquiries or phone contacts
 - provide a new multi-channel communication approach to reporting power cuts
- 4.6 During our pre-consultation engagement the company submitted a further presentation concerning the additional costs, over and above those already sought within RP6

Business Plan, to achieve an equivalent level of consumer and stakeholder engagement with its comparator DNOs. NIE Networks has claimed an additional £230k per annum is necessary to deliver equivalent consumer services effort to GB.

- 4.7 We are of the view that such additional costs (i) are already included in equivalent GB DNO costs (benchmarked to NIE Networks within our Indirects and IMF&T efficiencies), (ii) protect the company's "brand" and/or (iii) are very likely to reduce the overall cost of their customer service effort by adopting industry best practice where increased customer satisfaction leads to lower repeat contacts (which tend to burn resources).
- 4.8 We expect NIE Networks to engage in continuous engagement, equivalent to GB DNOs, since they are adequately funded to do so under our approach to efficiency benchmarking (Indirects and IMF&T).
- 4.9 The Consumer Engagement Advisory Panel (CEAP), our collaborative partnership approach to RP6 is expected to continue to make progress in the development of new customer focused measures/metrics, subject to the following requirements:
- comparability with other service providers
 - whether the metrics provide "actionable data" for the company
- 4.10 To enable cross-utility comparison of consumer satisfaction with their local, monopoly network providers we have already introduced a customer advocacy question⁶ into NI Water's regular consumer research.
- 4.11 The Consumer Engagement Oversight Group (a similar collaborative partnership group under water who were responsible for the delivery of consumer research to inform NI Water's last price control) facilitated the development of new surveys (replacing older, outdated surveys) which now provide NI Water with actionable data⁷ from both:
- province wide Omnibus Survey, including all of NI Water's customer base (representative samples of both domestic plus the industrial & commercial customer bases); and
 - quarterly surveys (unannounced) of customers who have contacted NI Water for whatever reason.
- 4.12 NIE Networks has expressed a desire to continue to work with the Utility Regulator to develop its existing customer surveys, perhaps to facilitate the consideration of a RP7 incentive around customer satisfaction scores.

⁶ Customer advocacy questions are commonplace questions, used in both public and private sectors and internationally. Customer advocacy feedback will allow us to compare local regulated monopoly networks to the very best organisations across the world.

⁷ Actionable data is required since gaining insight, without taking action, is of no real value. Data which is not actionable is, most simply, data that is not usable or useful.

- 4.13 Whether bilaterally, or through the CEAP, we are determined to bring in new customer advocacy measures of consumer satisfaction, through the RP6 period, with a view towards introducing these on a trial basis to inform RP7.
- 4.14 On this basis, we have included new customer advocacy and survey metrics within our RP6 developmental objectives.

Connections and contestability

- 4.15 NIE Networks has offered a number of outputs and KPIs for connections and contestability with the aim of offering an excellent service to connections customers whilst facilitating competition in connections.⁸ The KPIs and outputs fall within the broad categories listed below:
- Connections timelines⁹
 - Enhance the capability of the distribution network for generation connections¹⁰
 - Enhance engagement with customers
 - Improve processes and customer service
 - Contestability in connections
- 4.16 We understand that NIE Networks is not requesting an allowance in RP6 for these outputs.¹¹
- 4.17 The CEAP consumer and stakeholder research suggested that connections customer service was a key area for improvement – see its Recommendation 2. We recognise that NIE Networks has cited evidence of need for its proposed outputs on the basis of stakeholder and customer research which it has undertaken.
- 4.18 We propose to engage further with NIE Networks to discuss how these outputs can be developed, reported and monitored. We will also seek to understand how any actionable data can be gathered.

⁸ NIE Networks Business Plan submission to UE, Page 490.

⁹ Improving overall timeline to deliver a demand connection by 20%.

¹⁰ Complete managed connections trials and 33KV network reinforcement

¹¹ The exception to this is 33kv reinforcement general activity output (which sits within bullet 2 output above) and IT enhancements for contestability service level output (which sits within bullet 5 above).

Guaranteed Standards of Service (GSS)

- 4.19 NIE Networks currently work to restore 100% of customers who lose power supply within 24 hours, with the aim in its submission to move to an 18 hour standard by the end of the RP6 period.
- 4.20 We intend to examine the case to update the GSS to move from a 24 hour standard to one of 18 hours, although this is unlikely to be legally in place until well into RP6. We would note that the GB DNOs operate to a 12 hour standard. In the GB GSS regime, where 5,000 or more premises are affected by a single fault, a 24 hour standard applies. In addition, we intend to consider the introduction of categories of severe weather for supply restoration, similar to those currently in place in the GB regime.
- 4.21 We also intend to introduce annual reporting of all GSS and ex gratia payments to include performance against both an 18 hour and a 12 hour restoration period from October 2017. The reporting will be within the RP6 RIGs and we intend to publish this information in our annual cost and performance reports on the company's progress against the RP6 contract.

Background

- 4.22 The Utility Regulator has a statutory objective to protect the short and long term interests of consumers.
- 4.23 The guaranteed standards of service set out prescribed service levels which consumers can expect in individual cases. They include compensation payment requirements where there has been a failure by the company to adhere to the standards (subject to certain exemptions).
- 4.24 The current guaranteed standards of performance (performance in individual cases) were specified in Regulations made under Article 42 of the Electricity (NI) Order 1992 by the Director General of Electricity. The Electricity (Standards of Performance) Regulations Northern Ireland 1993 came into force on 1st January 1994. The Regulations were subsequently amended by the Electricity (Standards of Performance) (Amendment No 3) Regulations (NI) 1999 and the current standards have been in place since 1st October 1999.
- 4.25 In addition to GSS, there are Overall Standards (OSS) which set targets applicable to customers as a whole. No payments are attached to the OSS and these are specified in a Determination by the Utility Regulator made under Article 43 of The Electricity (Northern Ireland) Order 1992.
- 4.26 An effective performance standard mechanism can bring significant benefits to consumers. The mechanism can be used to ensure that consumers receive redress for inconvenience caused by poor service. It can also help to drive high quality customer service in the absence of sufficient competitive pressures.

Proposals

We are currently undertaking a review of the GSS regime to bring it up to date with the current regulatory and legislative environment. We issued a Call for Evidence in December 2016 and a Consultation is due to launch by the beginning of April 2017. The consultation sets out the proposal to bring the GSS regime in line with the level of consumer protection afforded in GB by the Electricity (Standards of Performance) Regulations 2015. It is proposed to make new GSS Regulations which are based on the GB GSS regime, but with adaptations to suit the Northern Ireland environment. At this stage, the review focuses on distribution and supply GSS, with connections GSS being considered at a later date. It is proposed to leave the OSS in place.

4.27 The key changes proposed in the Consultation Paper are as follows:

- A reduction in the restoration time due to a fault in normal weather conditions from 24 hours to 18 hours (where 5,000 or more premises are affected by a single fault, a 24 hour standard will apply);
- An increase in the compensation payment values to align with GB;
- An introduction of categories of “severe weather” for supply restoration;
- An introduction of GSS for multiple disconnections;
- An introduction of GSS for rota disconnection;
- A new standard for distribution companies in relation to responding to complaints;
- Automating most of the compensation payments for Critical Care Register customers (we will also consider extending this to vulnerable customers);
- Supplier GSS for appointments, charges, payments and complaints;
- New reporting - with the new regime we want to ensure that all payments made under the new regulations are reported annually (including goodwill payments) so that we have a measurable marker of performance. In the interests of transparency, we propose to publish the figures on our website.

4.28 The company also states they plan to improve restoration times, with 90% of customers restored within 3 hours by the end of RP6 (currently an 87% standard) and 100% restored within 18 hours by the end of RP6 (currently a 24 hour standard).

4.29 NIE Networks require sufficient time to adapt to the proposed changes to the GSS regime. However, as we have a statutory duty to protect the short and long term interests of consumers, we must respond to the need to update the GSS regime in a timely manner, given that consumer protection in GB has superseded that in NI.

4.30 As the review is at an initial stage, with new legislation required to be formally drafted and passed through the Department for the Economy and the Executive, we expect that

any new standards would not come into effect by October 2017, but during RP6. We believe that this time period will provide an adequate balance between updating consumer protection in this area and minimising the associated burden on business.

- 4.31 NIE Networks' business plan states that additional allowances would be required if higher Guaranteed Standards are imposed and that NIE Networks would propose a re-opener mechanism to allow for this.
- 4.32 However, the Utility Regulator view is that it would not be appropriate for consumers to cover the cost of implementation of a new GSS regime. This is particularly so in the circumstances where NIE Networks has set out its plan to work to an 18 hour standard and GB already operates to a 12 hour standard.
- 4.33 With the proposed new regime, where 5,000 or more premises are affected by a single fault, a 24 hour standard will apply. The period for restoration in severe weather events could also afford NIE Networks up to 48 hours before a GSS payment would be triggered.
- 4.34 There are also instances in which NIE Networks would be exempt from paying out on GSS, which include when NIE Networks cannot access a property or where the customer agrees to the electricity not being restored within the given timescales. It is proposed that with the new regime, these exemptions will still apply.

RP6 Developmental Objectives

- 4.35 As with previous water and gas network price controls, we plan to include various developmental objectives during the RP6 price control period. This is necessary to provide the time and space for considered engagement with the company / stakeholders to identify, define, trial and then introduce the new metrics as KPIs, prior to our reflecting on company progress within the reputational confines of our annual cost and performance reports.
- 4.36 RP6 developmental objectives will include, for example:
- Asset health and Load indices – we agree with the company these are not robust enough at the present time to inform asset management decisions. We plan to make load indices a component of the delivery of load related investment, as part of the development of asset management excellence during RP6
 - Worst served customers (WSC) – currently the company monitors to a different standard to GB DNOs and proposes to move to the GB DNO standard of, “someone who experiences six or more interruptions in an eighteen month period” during the RP6 period.
 - Monitoring of the new standard during RP6 will establish a robust time series to inform RP7, including whether to introduce targeted WSC standards and/or investments to improve WSC.

- new customer advocacy and survey metrics – to be developed wither bilaterally with NIE Networks or through the continued work of the CEAP, we intend to trial such in sufficient time to properly inform our next price control of NIE Networks at RP7. We also intend such new measures to inform the development of our annual cost and performance monitoring of NIE Networks as we move through the RP6 period.

RP6 Summary outputs, developmental objectives and KPIs

4.37 The following table summarises the various:

- outputs we expect consumers to benefit from during the RP6; alongside
- developmental objectives we expect to progress and develop through RP6; and
- new reporting requirements for NIE Networks (including new developmental or trial metrics and/or new reporting arrangements) or KPIs

RP6 Outputs	Timing	Notes
Ongoing consumer and stakeholder engagement	Throughout RP6	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan)
Capital projects	Throughout RP6	See technical Annex O – Assessment of Network Investment Direct Allowances and Annex P – Planned Network Investment Volumes and Allowances
Connections and contestability	Throughout RP6	See sub-section above: 'Connections and contestability'
Customer Minutes Lost (CML) / Reliability incentive (RI)	2018/19 onwards	See Technical Annex M – Reliability Incentive
Guaranteed Standards of Service (GSS)	2018/19 onwards	Subject to GSS Regulations being updated
Developmental objectives	Timing	Notes
Asset health and Load indices	Throughout RP6	Subject to reputational risk and annual commentary within Cost & Performance Report

		(RP6 Monitoring Plan)
Asset management development	Throughout RP6 and delivered for RP7 business plan submission.	To develop a plan for asset management development and report progress against the delivery of plan, with a focus on the RP7 business plan submission.
Worst served customers (WSC)	Early RP6	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan)
New customer advocacy and survey metrics	RP6 start through to Yr3	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan) AND subject to CEAP development
KPIs	Timing	Notes
Asset health and Load indices	Early RP6	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan)
Worst served customers (WSC)	Early RP6	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan)
New customer advocacy and survey metrics	Year 3 of RP6 at the latest for trialling of new metrics	Subject to reputational risk and annual commentary within Cost & Performance Report (RP6 Monitoring Plan) AND subject to CEAP development

Table 4: Summary outputs, developmental objectives and KPIs

4.38 Further development of the detail, planning and timing of the above will take place prior to the final determination. We are particularly interested in consultation feedback on

these proposals, especially where consultees consider we might need to either strengthen and/or include further outputs and KPIs for RP6.

Direct network investment outputs

- 4.39 The draft determination of direct network investment, which is described in Section 9 is based on a detailed bottom up assessment of investment proposed by NIE Networks including an assessment of the volumes of work which the company planned to deliver in RP6.
- 4.40 The types and volumes of outputs on which the draft determination is based are set out in Annex P. This excludes projects where the allowances will be determined at a later date under the D5 mechanism.
- 4.41 These outputs have been divided into two categories:
- i) Those where it has been possible to identify a volume of activities and associated costs. Unit cost have been calculated for these activities in Annex P
 - ii) Those where a lump sum has been identified to fund a general activity for which no specific outputs have been identified.
- 4.42 In principle, the company is to make all the investment necessary in RP6 to ensure compliance with licence conditions and relevant legislation subject to the incentive and uncertainty mechanisms set out in Sections 13 and 14, specifically:
- i) the cost risk sharing mechanism set out in Section 14 from paragraph 14.7;
 - ii) the inefficient spend clause set out in Section 14 from paragraph 14.9;
 - iii) the measures to tackle risks from the deferral of planned network investment set out in Section 14 from paragraph 14.11;
 - iv) the planned network investment substitution mechanism set out in Section 13 beginning paragraph 13.8.
- 4.43 In addition, the following nominated outputs shall be delivered in RP6:
- i) Resolution of all safety sign and staywire issues required under the Electricity, Safety, Quality and Continuity Regulations (ESQCR).
 - ii) Completion of all very high and high risk sites as defined by NIE Networks in their response to our query URQ091
 - iii) Refurbishment and re-conductoring of 33 spans of the Eden Main – Carrickfergus double circuit tower line to bring the asset to the company's asset standard. No further expenditure on this line would be expected in the foreseeable future.

- iv) At the end of RP6 there should be no more than 2% of the primary substation population operating at load index 5 according to the load index report included in the cost and volumes RIGs and this should be reflected in NIE Networks planned investment for RP7.
- 4.44 Subject to the delivery of these nominated outputs, the uncertainty and incentive mechanism which apply to direct networks investment provide the company with a wide degree of flexibility in the application of investment and the outputs it decides to deliver. In particular:
- i) There are no pre-defined outputs attached to direct network investment defined as lump sum activities in Annex P.
 - ii) No specific outputs are attached to the indirect costs including those associated with the delivery of direct network investment.
 - iii) The deferral mechanism allows the company to defer planned investment to subsequent price controls where the deferral can be demonstrated to be economic.
 - iv) The company has wide discretion to select the items of plant it decides to replace and refurbish within any allowance or sub-allowance.
 - v) The company can substitute investment and volumes between the various sub-allowances which make up an individual allowance where the volume of output is defined.
 - vi) The substitution mechanism proposed for RP6 allows the company to fund additional outputs across the plan by substitution of up to 20% of the investment from any other direct network allowance.

5 IMF&T and Indirects

Introduction

5

- 5.1 This Chapter assesses NIE Networks' Inspections, Maintenance, Faults and Tree cutting (IMF&T) and Indirect costs. IMF&T may be described as the investment made in order to maintain the day-to-day operation of the network. Indirect costs relate to functions that support direct activities, including categories of Closely Associated Indirect costs (CAI) and Business Support.
- 5.2 Closely Associated Indirects are costs that support direct activities, such as Network Design & Engineering, Project Management, Engineering Management and Clerical Support, System Mapping, Control Centre, Call Centre, Stores, Operational Training and Vehicles & Transport.
- 5.3 Business Support encompass 'overhead' type costs such as Network Policy, HR, Finance & Regulation, CEO, IT & Telecoms and Property Management.
- 5.4 For both NIE Networks and GB DNOs, IMF&T and Indirects include costs that are capitalised and costs that are not capitalised. As a result, our benchmarking analysis cuts across NIE Networks' capex and opex.
- 5.5 In setting an allowance for RP6, Indirect and IMF&T costs are split between opex and capex based on the proportion of NIE Networks' IMF&T and Indirect costs that were capitalised by NIE Networks in 2015/16. However, for the purposes of our benchmarking analysis we do not distinguish between IMF&T and Indirect costs which are capitalised and which are not capitalised.
- 5.6 A proportion of IMF&T and Indirect costs are allocated to connections for NIE Networks and GB DNOs. As a result, we have conducted benchmarking on a pre-allocation of IMF&T and Indirect costs to connections basis (gross) and a post-allocation of IMF&T and Indirect costs to connections basis (net).
- 5.7 We assess other opex separately, such as costs for severe weather, rates and licence fees, and this is detailed in Chapter 6. Frontier Shift for both opex and capex is assessed separately in Chapter 10.

RP5

- 5.8 RP5 IMF&T and Indirect expenditure was set by the Competition Commission (now referred to as the Competition and Markets Authority (CMA)) as part of its work during

the RP5 price control referral. The CC arrived at their allowances through econometric benchmarking of NIE Networks with Distribution Network Operators (DNOs) in Great Britain (GB).

- 5.9 The CC compared NIE Networks to the fifth placed company out of 15 DNOs and established a range of efficiency scores, against four different approaches to the wage adjustments. After assessing the results of the models, the CC determined that for 2011/12, an approximate 6% reduction was warranted for NIE Networks' IMF&T and Indirect costs, including the 275kV network.¹² These findings, combined with other analyses undertaken by the CC, were then carried forward into RP5 allowances for NIE Networks. It is important to note, however, that qualifying opex and qualifying capex were subject to a 50/50 sharing mechanism between the company and its customers.¹³
- 5.10 As part of NIE Networks' RP6 submission to the Utility Regulator, the company provided RP5 outturn opex for the period 2012/13 to 2015/16 (4 years). We can use this information to gain an insight into whether or not NIE Networks outperformed its opex allowance during the first four years of RP5. In turn, we compare NIE Networks' actual IMF&T and Indirect expenditure with the corresponding allowances that were set as part of the RP5 price control review.
- 5.11 The figure below outlines IMF&T and Indirect allowances and actual expenditure in the period 2012/13 to 2015/16 (distribution plus transmission), excluding atypical severe weather. The chart shows that NIE Networks overspent their allowance in the first two years of the price control period by approximately £3 million in each year.
- 5.12 In 2014/15 and 2015/16, the company's actual expenditure is approximately in line with their allowances, with a slight out-performance of around £250,000 in 2014/15. This chart will be updated for the rest of RP5 (2016/17 and 2017/18)¹⁴ once we receive the outturn actual data, in due course.
- 5.13 It is important to note that until we understand NIE Networks' actual expenditure for the entire RP5 period (April 2012 to September 2018), it is difficult to gain a full insight into NIE Networks' over- or under-performance during RP5.

¹² In paragraphs 8.223-8.224 of the RP5 determination, the CC set a cost benchmark of £53.6m versus a NIE cost of £57.0 for the 2011/12 year. Paragraphs 7.35-7.36 of the CC's RP5 determination document how this was rolled forward in real terms.

¹³ Further information can be found in Chapter 19 of the CC RP5 Final Determination document

¹⁴ The RP5 regulatory period runs until the end of September 2017 (i.e. the first 6 months of 2017/18).

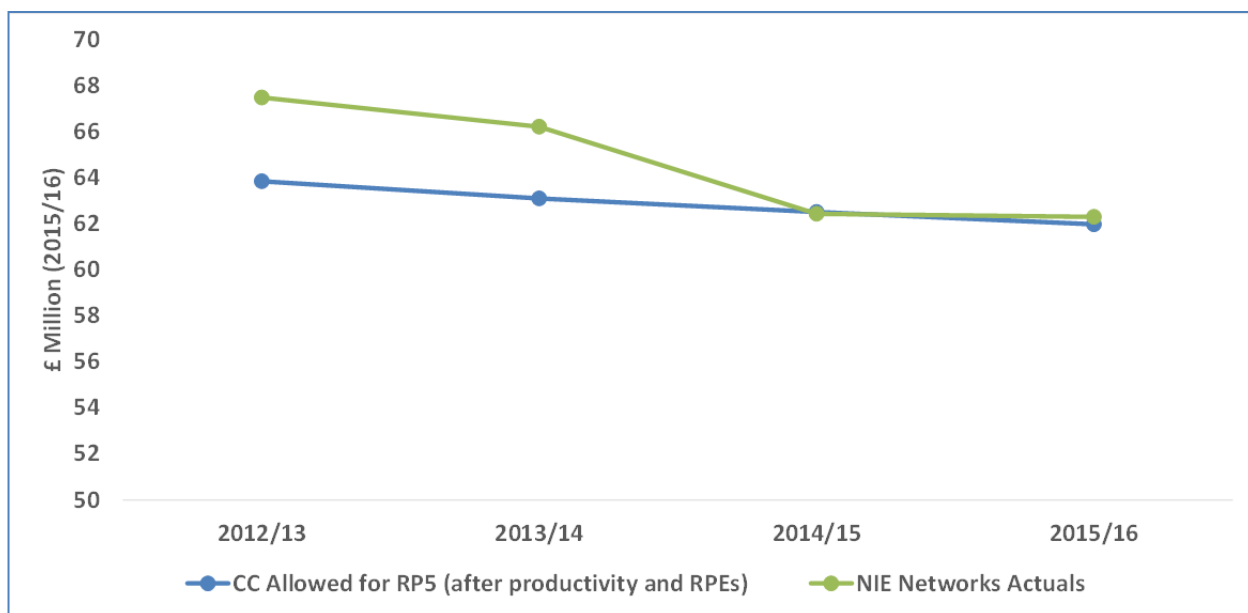


Figure 4: Indirect and IMF&T expenditure (excluding atypical severe weather) - 2012/13 to 2015/16

Assessment of efficient IMF&T and Indirect expenditure (distribution)

Introduction

- 5.14 Benchmarking is essentially the process of comparing a firm's costs and performance to the industry best or best practices from other similar companies. For the Utility Regulator this effectively means comparing the relative performance of NIE Networks to those DNOs that operate in Great Britain (using Ofgem data). As electricity distribution companies are natural monopolies, regulatory benchmarking may be necessary to drive down costs and improve quality of service in the absence of competitive pressures.
- 5.15 Benchmarking has been adopted by regulators around the world, including regulators such as Ofgem, Ofwat, Office of Rail and Road (ORR) and the Water Industry Commission for Scotland (WICS) in Great Britain. In Northern Ireland, the Utility Regulator has undertaken econometric and unit cost benchmarking of NI Water for a number of its price controls (namely PC10, PC13 & PC15), with notable success. For example, since 2007-08 the Utility Regulator has seen NI Water's operational efficiency gap reduce considerably, from an estimate of 49% in 2007-08, to around 13% in 2014-15. Since the start of PC10, annual operational expenditure in the water and sewerage business has reduced by around £60m in real terms.¹⁵

¹⁵ Calculated as the difference in operational spend between 2009-10 (year immediately before PC10) and 2014-15.

- 5.16 The Utility Regulator has also introduced opex benchmarking for GD17, comparing the historic and business plan costs of the Gas Distribution Network companies (GDNs) in Northern Ireland to their counterparts in GB.¹⁶ This was the first time such comprehensive benchmarking of opex had been undertaken in Northern Ireland's natural gas distribution industry.
- 5.17 For RP6 the Utility Regulator has undertaken benchmarking to assess efficient distribution IMF&T and Indirect expenditure for NIE Networks. Cambridge Economic Policy Associates (CEPA), utilising expert modelling advice from Dr Andrew Smith, developed the econometric models used by the Utility Regulator for the RP6 draft determination, and were involved from an early stage in the process.¹⁷
- 5.18 We have benchmarked distribution IMF&T and Indirect expenditure that are both "controllable" and "comparable". By "controllable", we refer to costs that are to some degree within management control; and by "comparable", we refer to costs that are incurred by all DNOs and smooth across time - therefore comparable in scope.
- 5.19 Our focus is on benchmarking IMF&T and Indirect costs attributable to the distribution network as there are fewer transmission operators (TOs) in GB than DNOs, which makes the benchmarking of electricity transmission more difficult (14 DNOs compared to only 3 TOs). However, as GB DNOs operate high voltage 132kV lines, we allocate NIE Networks' IMF&T and Indirect costs attributable to 110kV transmission assets to their distribution business in order to improve comparability. Additional data adjustments have also been made, which are discussed below.
- 5.20 The benchmarking techniques we have examined in RP6 include:
- Pooled Ordinary Least Squares (POLS) regression analysis;
 - Random Effects (RE) estimation; and
 - Unit Cost comparisons.
- 5.21 The Utility Regulator and CEPA met NIE Networks on 23 March 2015 to discuss how the Utility Regulator aimed to build on the benchmarking undertaken by the CC during RP5. The Utility Regulator stated how it was minded to apply approaches and principles used by the Utility Regulator in its other network price control determinations (namely for NI Water and the gas distribution network companies (GDNs) in Northern Ireland for GD17) as well as best practice from other regulatory determinations, including from the Competition and Markets Authority (CMA).

http://www.uregni.gov.uk/uploads/publications/final_Cost_and_Performance_Report_for_PC13_-_embargoed_until_1200_26th_Nov_2015_final_v.pdf

¹⁶ The top-down model estimates were used at GD17 as a 'sense-check'.

¹⁷ Dr Andrew Smith is a Senior Lecturer in Transport Regulation and Economics and Research Group Leader for the Economics and Discrete Choice Research Group at the Institute for Transport Studies, University of Leeds (joint position with Leeds University Business School). He was academic advisor to OFWAT on econometric efficiency analyses, including 2015 CMA enquiry.

- 5.22 CEPA undertook a number of data adjustments to both NIE Networks and to the 14 GB DNOs to ensure as like-for-like a comparison as possible. Only costs that were deemed “controllable” and “comparable” were included in the benchmarking data set. Most notable exceptions include atypical severe weather, rates and pension deficit costs, which we have assessed separately. Using this data, CEPA developed and estimated a number of econometric and unit cost models in order to ascertain the likely efficiency performance of NIE Networks.
- 5.23 The Utility Regulator met with NIE Networks on 19 December 2016 to share some preliminary results from CEPA’s benchmarking analysis before this draft determination. Furthermore, we also shared a draft version of CEPA’s benchmarking paper with NIE Networks on 3 March 2017 ahead of this draft determination.
- 5.24 The overall approach to benchmarking taken by CEPA, and the application of benchmarking results to baseline expenditure, are summarised in the diagram below:

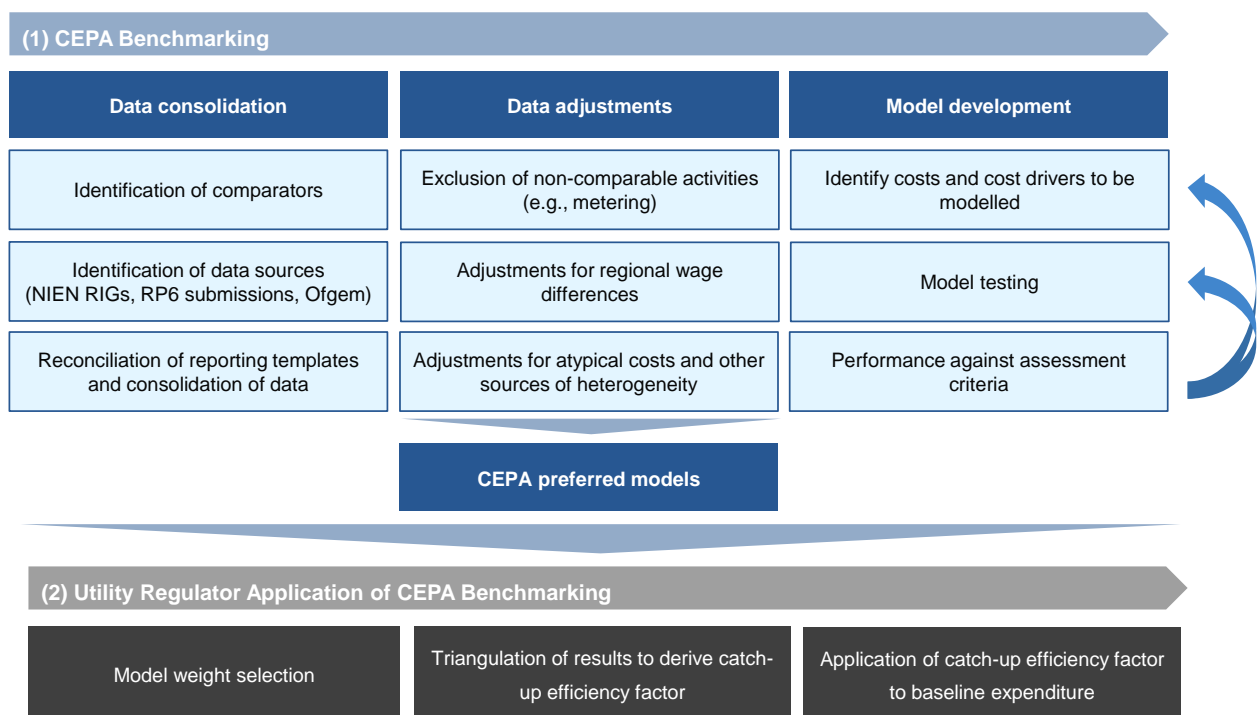


Figure 5: Summary of benchmarking and cost assessment approaches

NIE Networks' own benchmarking analysis for RP6

- 5.25 As part of the RP6 process the Utility Regulator asked NIE Networks to provide evidence that it had undertaken its own assessment of company efficiency levels. In our RP6 Final Overall Approach document from December 2015 we stated the following:

*"We expect NIE Networks to have carried out sufficient benchmarking to inform its decision on the scope for improving efficiency that it has included in its RP6 Business Plan. We expect to see this justification together with information for us to be able to carry out benchmarking checks against peer enterprises operating elsewhere in the UK and Europe."*¹⁸

- 5.26 In their RP6 business plan, NIE Networks state that since being privatised in 1993, they have implemented a series of initiatives and programmes designed to improve efficiency, resulting in a 33% reduction in network charges since privatisation.¹⁹
- 5.27 NIE Networks provided a number of papers from NERA evidencing their own efficiency benchmarking analysis as well as their own Regional Labour Cost Adjustment work.
- 5.28 NERA incorporated NIE Networks into Ofgem's RIIO ED1 benchmarking models, along with their own Regional Labour Cost Adjustment, re-estimated the models, and used the results to assess the efficiency of NIE's indirect and IMF&T costs. Some of the models which NERA used utilised forecast data from RIIO ED1. NERA stated that Ofgem benchmarking methodology shows no evidence of technical inefficiency embedded within NIE Network's current level of indirect and IMF&T costs.
- 5.29 NERA also stated that implementing the benchmarking methodology used by the CC at RP5 results in an efficiency gap over the same period that is very small (below 1%), with NERA suggesting NIE Networks is approximately on the frontier.
- 5.30 A separate paper on special factors was also provided by NIE Networks and NERA. NERA state that this should also be considered in conjunction with their overall findings:

"The accompanying NERA report on special factors concludes that there are some specificities of NIE's business and service region that are not entirely controlled for in the Ofgem benchmarking models. Our analysis demonstrates that some special factors have a positive effect on NIE's costs, and others have a negative effect. On balance, therefore, these differences between NIE and the British DNOs do not undermine the conclusion that NIE's current level of indirect and IMFT costs are efficient."

¹⁸ Paragraph 4.40 of the Utility Regulator's RP6 Final Approach Document.
https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/2015-12-22_RP6_Final_Approach_Document_-_final.pdf

¹⁹ Paragraph 2.31 of NIE Networks' RP6 Business Plan.
http://www.nienetworks.co.uk/documents/Future_Plans/Summary-business-plan-with-links.asp

“In fact, if anything, the results of the Ofgem modelling probably understate NIE’s efficiency, by failing to account for the economies of scale in business support activities the larger DNOs in Great Britain can achieve. In our accompanying report, we estimate that NIE’s efficient costs during RP5 are probably understated by the Ofgem modelling presented in this report by around £1.6 million per annum. We estimate that the CC modelling also underestimates NIE’s efficient costs by approximately the same amount during RP5.”

- 5.31 NIE Networks subsequently updated the analysis undertaken at business plan submission stage with the latest 2015-16 data, however they considered their findings had largely stayed the same. In NERA’s latest benchmarking submission to the Utility Regulator, dated 31 October, they state:

“....our updated analysis demonstrates that, based on the benchmarking methodology used by Ofgem at the RIIO-ED1 price control review, NIE achieves an efficiency gap of minus 3.1% on average over the 4-year period between 2012/13 and 2015/16. This compares to an efficiency gap of minus 4.2% we estimated in our June report.”

“Hence, according to this updated benchmarking using 4 years of data NIE still outperforms the upper quartile efficient DNO by 3.1% and is ranked second in terms of efficiency. Hence, our updated modelling shows no evidence of inefficiency embedded in NIE’s current levels of indirect and IMFT costs.”

- 5.32 The Utility Regulator acknowledges that NIE Networks have undertaken a considerable amount of analysis within its benchmarking submission and Regional Labour Cost Adjustment work and this has proved informative for the Utility Regulator in setting its RP6 draft determination.
- 5.33 It is clear that NIE Networks and NERA have been constructive and transparent in explaining their efficiency approach and methodology. NIE Networks and NERA have shared the underlying data and models they used with the Utility Regulator.
- 5.34 However, in examining the methodology undertaken, there are certain aspects of the analysis undertaken by NIE Networks in which we diverge. Therefore, in order to ensure consumer interests are fully protected, the Utility Regulator, assisted by CEPA, has undertaken its own benchmarking analysis for RP6.
- 5.35 Our methodology and results are laid out in the sections below.

GB DNOs as comparators

- 5.36 Following the approach taken by the CC at RP5, we benchmark NIE Networks with GB Distribution Network Operator companies (DNOs).
- 5.37 The electricity network in Northern Ireland is made up of a transmission and a distribution component.²⁰ NIE Networks has responsibility for the running of its distribution system, which covers lines of less than 110kV. However due to EU requirements for the independence of certain activities, NIE Networks shares the responsibilities of running its transmission network. Transmission related responsibilities are split between NIE Networks and a separate body, the System Operator for Northern Ireland (SONI).
- 5.38 In GB there are 14 DNOs which own and operate electricity distribution network assets within a defined geographical area. Allowances for the regulatory period 2015/16 to 2023/24 have been set by Ofgem within their RIIO-ED1 price control. GB DNOs typically cover the network from 132kV down to the low voltage network. Electricity transmission services are provided by three onshore transmission operators (TOs), and are independent from DNOs. For the purposes of this benchmarking exercise, we focus on GB DNOs.
- 5.39 The table below summarises the characteristics of UK electricity distributors (customer numbers, length of network and units distributed) and actual totex in 2015/16, as published in the RIIO-ED1 Annual Report 2015/16.²¹
- 5.40 In terms of customers served, the smallest DNO (SSEH) serves around 760,000 customers, while the largest (EPN) serves around 3,600,000 customers. NIE Networks operates towards the lower end of this range, with approximately 855,000 customers, but still comparable to the GB DNOs in terms of scale. With around 17.6 customers per km of network, NIE Networks is one of the most rural DNOs, with LPN from London clearly the most urban, having 62.6 customers per km line of network.
- 5.41 Overall, NIE Networks is one of the smallest distributors in the UK, and is similar in terms of size and network characteristics as Scottish Hydro Electric Power Distribution (SSEH) who operate in the North of Scotland. However, NIE Networks appears to be comparable to the GB DNOs in terms of scale.

²⁰ Transmission in Northern Ireland relates to electricity lines of 110,000 volts or greater (275kV, 110kV). Distribution in Northern Ireland relates to lines of less than 110,000 volts (33kV, 11kV, 6.6kV and below), all the way down to the service cable that goes to the meter in homes and businesses.

²¹ Source: Ofgem RIIO-ED1 Annual Report 2015/16.

Company	Actual totex	Customer numbers	Line length (km)	Customers / km line
EMID	£308m	2,622,449	72,976	35.9
ENWL	£244m	2,381,080	57,946	41.1
EPN	£281m	3,599,594	97,261	37.0
LPN	£189m	2,311,906	36,933	62.6
NPGN	£188m	1,596,374	41,244	38.7
NPGY	£248m	2,291,522	53,874	42.5
SPD	£192m	2,002,257	57,984	34.5
SPMW	£239m	1,503,914	46,844	32.1
SPN	£173m	2,281,009	52,841	43.2
SSEH	£151m	762,398	48,332	15.8
SSES	£276m	3,016,250	78,012	38.7
SWALES	£142m	1,122,920	35,612	31.5
SWEST	£223m	1,590,050	50,248	31.6
WMID	£312m	2,463,217	64,269	38.3
GB Average	£226m	2,110,353	56,741	37.2
NIE Networks	£176m	854,580	48,659	17.6

Table 5: Background DNO company information (2015/16) ²²

- 5.42 It is also important to compare companies in terms the quality of service (i.e. reliability). While a company may have lower day-to-day costs than another, it is important to ensure that such performance is not at the expense of safety, customer service and reliability.
- 5.43 The Utility Regulator has therefore compared NIE Networks' customer service performance with GB DNOs. With regards to network reliability and resilience, there are three reliability measures that can be compared across companies:
- The number of customer interruptions per 100 customers (CI)

²² GB totex data from page 8 of Ofgem's RIIO-ED1 Annual Report 2015/16.

<https://www.ofgem.gov.uk/publications-and-updates/riio-electricity-distribution-annual-report-2015-16>

Customer numbers and network length taken from each DNO's published key summary information.

- Customer minutes lost (CML)
- Average restoration time per customer interruption (CML / CI)

5.44 We examine four years of GB DNO and NIE Networks performance in terms of the three metrics described above (2012/13 to 2015/16) and the results are shown in the graphs below.²³ It should be noted however, that outages of more than three minutes are included in the GB definition. This is different from NIE Networks where CI and CML numbers are recorded after one minute.

5.45 In addition, it is also the case that some differences exist on severe weather events between Northern Ireland and Great Britain.

5.46 In order to ensure a fairer comparison we exclude severe weather events from company data, which are out of the control of the DNO. These events must meet pre-determined thresholds to be excluded from final performance values.

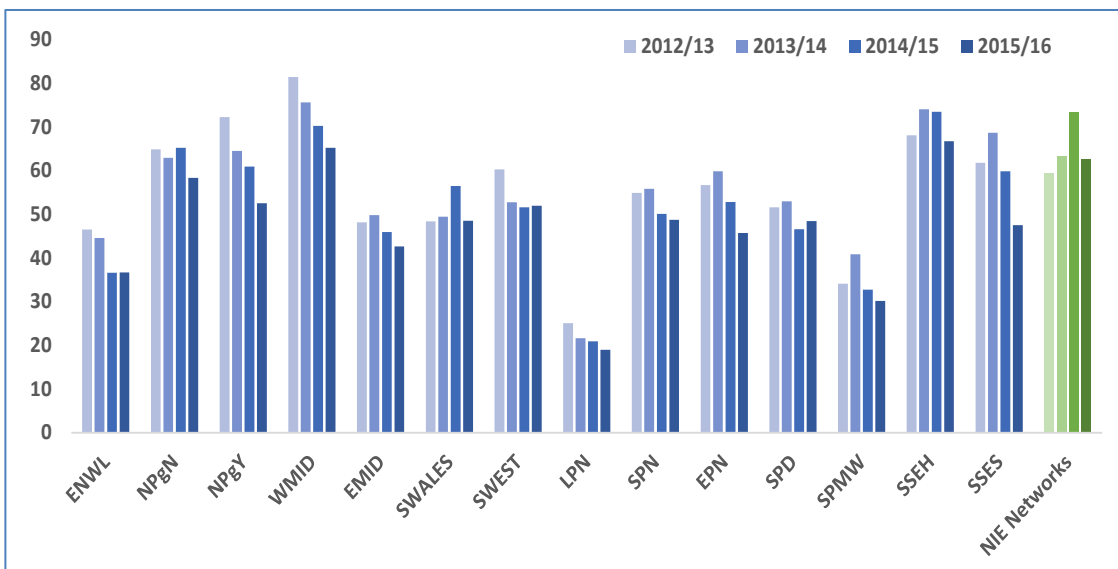


Figure 6: Customer interruptions per 100 customers – 2012/13 to 2015/16

5.47 In the four years of data examined (2012/13 to 2015/16), NIE Networks faced a similar number of customer interruptions per 100 customers as WMID and SSEH. In contrast, LPN who operate in London, experience the least number of customer interruptions of the 15 DNOs, averaging only 22 customer interruptions per 100 customers over the period. Overall, customer interruptions in 2015/16 range from 19 (LPN) to 67 (SSEH) per 100 customers.

²³ GB CI and CML data from Ofgem's RIIO-ED1 Annual Report 2015-16 and DPCR5 Company Performance Report 2010-2015.
<https://www.ofgem.gov.uk/publications-and-updates/riio-electricity-distribution-annual-report-2015-16>
<https://www.ofgem.gov.uk/publications-and-updates/electricity-distribution-company-performance-2010-2015>

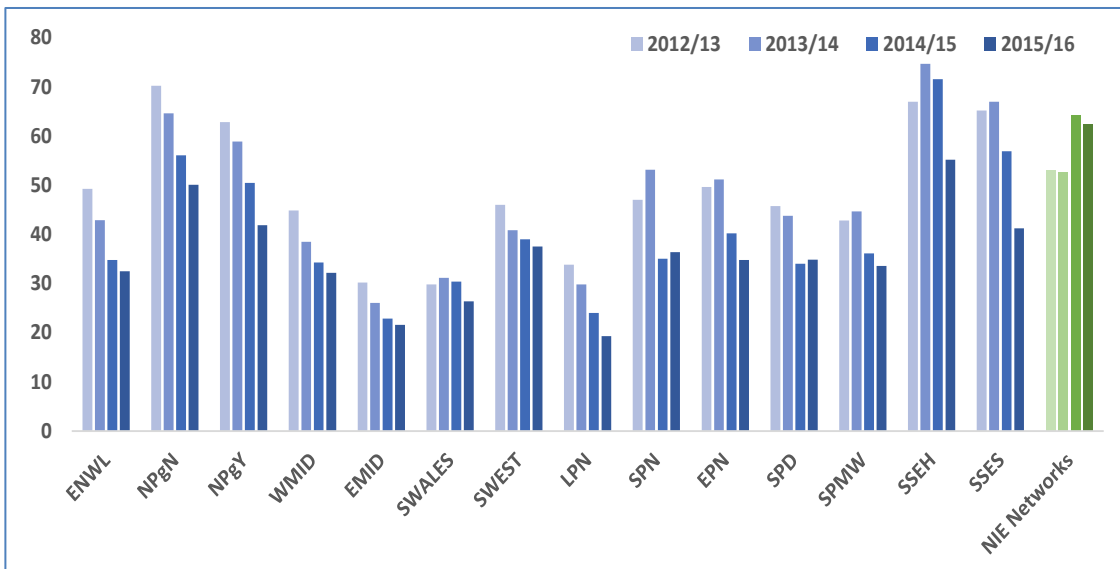


Figure 7: Customer minutes lost – 2012/13 to 2015/16

5.48 In terms of customer minutes lost over the period 2012/13 to 2015/16, NIE Networks faced a similar figure as SSEH and NPgN. Overall, CML in 2015/16 range from 19 (LPN) to 62 (NIE Networks).

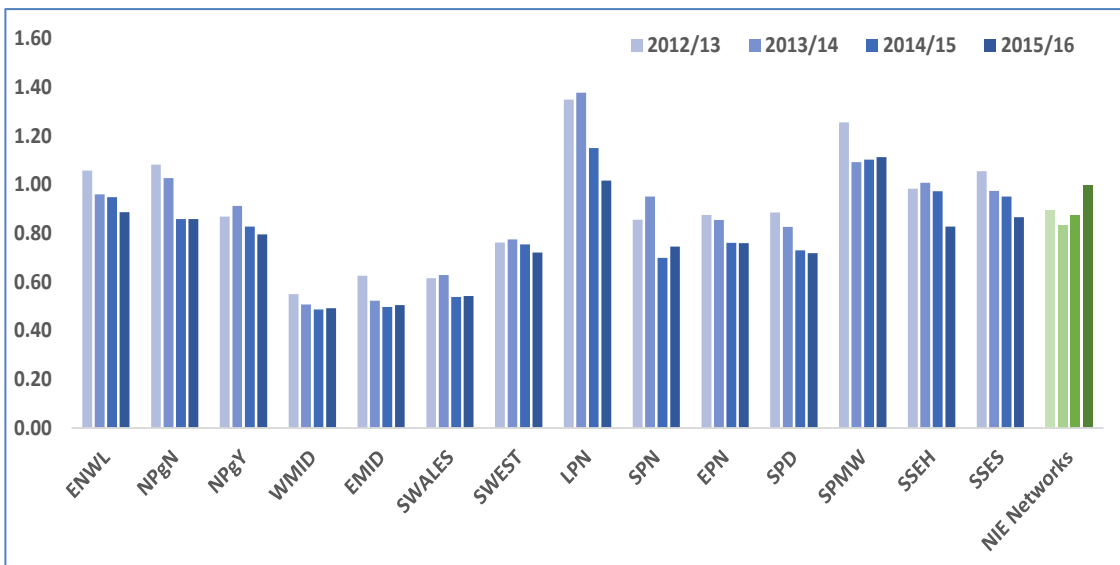


Figure 8: Customer minutes lost per customer interruption – 2012/13 to 2015/16

5.49 Ofgem at RIIO-ED1 used CML per CI, a proxy for average restoration time, to benchmark DNOs in terms of reliability performance. Over the period 2012/13 to 2015/16, NIE Networks' average restoration time was comparable to GB DNOs. NIE Networks were ranked 9th in 2012/13, 6th in 2013/14, 10th in 2014/15 and 13th in 2015/16.

5.50 Generally speaking, from the analysis we have undertaken, we consider that comparing the relative costs of NIE Networks with the GB DNOs to be entirely

appropriate from a service quality point of view and from a scale point of view. Differences in scale can be appropriately controlled for in the benchmarking by including scale variables within the econometric models (i.e. customer numbers, network length and units distributed). In addition, while there are naturally differences in the levels of service between all the DNOs used in the benchmarking, none of these differences are so material as to invalidate any cost comparison.

5.51 It is important to note, however, that while in general terms the level of service performance is comparable between NIE Networks and GB DNOs, the standards and policies to which NIE Networks operate are slightly different. Examples include:

- i) Guaranteed standards - NIE Networks currently operate at a 24 hour standard during RP5 whereas GB DNOs operated to a 18-hour standard at DPCR5 and now to a 12 hour standard at RIIO-ED1.
- ii) Consumer engagement –higher levels of consumer engagement are conducted by GB DNOs on average than by NIE Networks.
- iii) Innovation –higher innovation expenditure by GB DNOs than NIE Networks, on average.
- iv) ESQCR – GB DNOs currently operate to higher ESQCR standards than NIE Networks.

5.52 It is important to note that the four factors listed above could arguably warrant a negative special factor adjustment(s) within CEPA's comparative benchmarking, i.e. increase NIE Networks' modelled costs within the benchmarking exercise. However, for this draft determination we have not made such an adjustment.

Data sources

5.53 NIE Networks have populated the Utility Regulator's RP6 Business Plan Templates (BPTs) which have been structured by the Utility Regulator to facilitate benchmarking with GB DNOs. In addition, the Utility Regulator has also relied upon NIE Networks' Regulatory Instructions and Guidance (RIGs), which have been populated with data up to 2015-16. Additional bespoke data has been provided by NIE Networks when requested by the Utility Regulator during the business plan query process.

5.54 We are grateful to Ofgem (the Regulator of the gas and electricity industries in Great Britain) for providing the Utility Regulator with the comprehensive data which allows us to undertake this benchmarking analysis. Ofgem provided the Utility Regulator with detailed data used in their RIIO-ED1 determination, which included historic outturn data and company forecasts. Ofgem also provided company RIGs data from the 14 DNOs, which included one additional year of outturn data (2015/16). As a result, we had access to 6 years of historical DNO data from 2010/11 to 2015/16.

- 5.55 For our RP6 benchmarking models we decided not to rely upon ED1 forecasts or allowances but solely rely upon historic outturn data. The use of historic data is the same approach as was adopted by the Utility Regulator during its NI Water price controls (PC10, PC13 & PC15) as well as in GD17. This is in contrast to NIE Networks' benchmarking analysis, which frequently used forecast data.
- 5.56 By focusing on historic data we ensure that allowances for RP6 are set on what should be currently technically achievable when it comes to actual efficiency levels, rather than relying upon forecasts which may prove to be mistaken in hindsight.
- 5.57 Throughout this benchmarking exercise our preference has been to use a balanced panel. As a result, we have only used the most recent four years of available GB data within our benchmarking analysis (2012/13 to 2015/16). As we have 15 DNOs (including NIE Networks), pooling across the four years means we have a sizeable sample of 60 observations. The Utility Regulator considers this is a long enough time-series of historic data to allow a robust set of models to be estimated.

Data adjustments

- 5.58 We have made a number adjustments to the data to account for: differences in the scope of activities / assets; non-controllable costs; atypical costs; re-allocation of costs; DNO-specific costs and other regional factors. These adjustments are made in advance of benchmarking, and are necessary in order to avoid differences between companies that are not related to inefficiency.
- 5.59 These adjustments are summarised below but more detailed information can be found in CEPA's RP6 Efficiency Advice Paper in Annex B to this draft determination.

Differences in the scope of assets

- 5.60 In GB, there are 14 DNOs and 3 TOs. There are 12 DNOs in England and Wales which operate networks with voltages up to and including 132kv. National Grid operates a separate transmission network at voltages of 275kv and 400kv. Scotland has two regional DNOs, operating networks with voltages up to 33kv. Voltages of 132kv and above are categorised as transmission in Scotland.
- 5.61 Therefore, in order to ensure a like-for-like comparison with GB DNOs, the Utility Regulator allocates NIE Networks' 110kv transmission related costs to distribution. This essentially means that we compare NIE Networks' 110kv and below network costs with GB DNOs' 132kv and below network costs (except Scotland). This is adopting a similar approach as the CC undertook during their determination of RP5. In turn, this means we exclude NIE Network's 275kV transmission costs from the benchmarking.

Differences in scope of work undertaken

- 5.62 NIE Networks incur costs associated with metering but GB DNOs do not. As a result, we have excluded metering costs, market opening costs, and indirect costs associated with metering from NIE Networks costs. For similar reasons, we exclude costs reported by GB DNOs related to non-distribution activities.
- 5.63 There are also a number of DNO specific costs that are incurred by a single, or small number, of DNOs, which we have excluded. These costs include: regional factors applied by Ofgem at RIIO-ED1 for London Power Networks (LPN), SSEH and Scottish Power Manweb (SPMW); streetworks costs; ETR 132 tree cutting costs; and “Network Operating Costs (NOCs) other”.
- 5.64 The Utility Regulator has not excluded wayleave payments from our benchmarking. At RP5 the CC noted that NIE Networks faces trade-offs between the costs of wayleaves payments to landowners (which were aligned with Scottish Power), administrative costs of its wayleave payment process and the benefits of landowners’ goodwill. Taking these factors into account, the CC considered that the rates paid by NIE Networks is a controllable choice by the company and included these costs in its IMFT and Indirects models. The Utility Regulator has taken the same approach at RP6.

NIE Networks’ atypical costs

- 5.65 It is important to exclude any one off atypical costs so that the resulting efficiency gap represents a true reflection of relative cost performance. Taking this into account NIE Networks were asked to submit any atypical IMF&T and Indirect cost items incurred during RP5 within their benchmarking submission to the Utility Regulator for RP6.
- 5.66 Each potential atypical cost has to be assessed by the Utility Regulator to ascertain whether it is appropriate to be included or excluded from the models. NIE Networks submitted two atypical cost claims within their submission: costs associated with the Competition Commission referral and costs associated with the North-South Interconnector. We accepted both claims, and hence excluded these costs from the benchmarking.
- 5.67 Furthermore, we have excluded atypical severe weather costs from our benchmarking since severe weather event costs will differ significantly across time and across companies. We have arrived at a separate allowance for atypical severe weather costs for RP6, which is discussed in Chapter 6 below.

Other cost exclusions - rates, licence fees & pension deficit repair costs

- 5.68 While the majority of firms will incur expenditure such as rates, licence fees and pension deficit repair costs to some degree, we deem these costs to be somewhat outside the control of the company. As a result, we have excluded these costs from our benchmarking. For clarity, ongoing pension costs are included within the IMF&T and

Indirects base costs so that it is only those pension deficit repair costs which are given separate treatment within our Financial Model.

Re-allocation of costs – connections

- 5.69 A share of indirect opex costs incurred by NIE Networks are allocated to connection activities, which are treated outside of the price control as connection costs are funded through customer connection charges. Compared to GB DNOs, NIE Networks appears to be allocating a relatively high proportion of indirect costs to connections, with a noticeable step-change in the allocation rate in 2014/15. NIE Networks have stated that this is caused by a ramp up in connection work. As a result, if we conduct benchmarking on a post-allocation basis this would improve NIE Networks' efficiency performance as a larger share of indirect costs would be excluded from the assessment.
- 5.70 To account for these effects CEPA have run models on both a pre- and post-allocation basis. This means we have run models on a gross cost basis, where we do not allocate a proportion of indirect costs to connections, and on a net cost basis, where we do allocate a proportion of indirect costs to connections. This is similar to the approach taken by the CC at RP5.
- 5.71 There are advantages and disadvantages of both approaches, as was highlighted by CC at RP5. The pre-allocation approach does not create any adverse incentive to inefficiently allocate indirect costs to connections. On the other hand, it requires the modelling of both regulated and unregulated costs, which in turn requires the Utility Regulator to make a gross to net adjustment when applying the catch-up efficiency factor to baseline costs. Conversely, the post-allocation approach focuses on regulated costs and does not require us to determine the share of opex to be allocated to connections. However, this approach could create distortions in the relationship between costs and costs drivers, and has the potential to adversely incentivise NIE Networks to allocate a large proportion of indirect costs to connections. By running models on a pre- and post-allocation basis we have effectively managed the trade-off between using both approaches.

Re-allocation of costs – other

- 5.72 NIE Networks' vehicle costs differ from those of GB DNOs as they lease all of their vehicles whereas GB DNOs have a mixture of leasing/buying. To account for this difference we have included DNO non-op capex relating to vehicles in closely associated indirect (CAI) costs. This is similar to the approach taken by Ofgem at RIIO-ED1. Similarly, we have allocated non-op capex relating to property to business support property management costs.
- 5.73 However, we have not allocated non-op capex relating to IT & Telecoms and Small Tools, Equipment, Plant & Machinery (STEMP) as this expenditure is lumpy, which makes comparisons across time and companies difficult. Alternatively, non-op capex

relating to IT & Telecoms is being assessed separately by Gemserv,²⁴ and we propose to apply the derived catch-up efficiency factor from our benchmarking to 2015-16 STEPm baseline costs. Both of these decisions have been discussed with NIE Networks in advance of this draft determination.

Regional wage adjustment

- 5.74 In order to ensure that companies are not unfairly advantaged by being situated in a low-cost region for labour or disadvantaged by being situated in a high-cost region we apply a regional wage adjustment (RWA) to each company's costs in advance of benchmarking.
- 5.75 Regional wage and price variations are taken into account by a number of economic regulators of network companies, including by Ofwat (PR14) and Ofgem (RIIO-GD1 and RIIO-ED1). The CC determination of NIE Networks for RP5 made a wage adjustment between the different companies used in its benchmarking, including NIE Networks.
- 5.76 In PC15, in assessing NI Water's capex programme, the Utility Regulator undertook a regional price adjustment which took into account lower procurement prices in Northern Ireland than in England and Wales. For our opex efficiency models, we implemented a negative special factor upon NI Water to take account of lower wage levels in Northern Ireland for PC10, PC13 and PC15. Similarly, a regional wage adjustment was used in GD17 by the Utility Regulator to adjust the opex costs for the GDNs which were benchmarked.
- 5.77 The Utility Regulator has been advised by CEPA on the various approaches which can be undertaken with regards to applying a RWA. We have accepted CEPA's advice and used their baseline approach to provide a central estimate of NIE Networks' efficiency levels. CEPA's advice to the Utility Regulator is to adopt a regional wage adjustment for NIE Networks of 0.877 (i.e. -12.3%). This means that we would expect NIE Networks' labour costs on average to be 12.3% lower than the UK average. While Northern Ireland has a negative RWA, London for example has a positive RWA, as it is widely recognised as a high cost region.²⁵ CEPA's baseline RWA is calculated under the following assumptions:
- i) 12 region split;
 - ii) 2-digit SOC code;
 - iii) Mean hourly wages excluding overtime; and
 - iv) Approach to averaging: first apply the SOC code weights; then take the ratio between the region in question and the UK; and then average across time (SOC; x/UK; years).

²⁴ See CEPA's Regional Wage Adjustment paper in Annex A.

²⁵ A positive RWA will mean that its opex costs are adjusted downwards for the models.

- 5.78 In addition to adopting CEPA's preferred approach as a baseline, the Utility Regulator has been guided by the CC's determination for NIE in RP5 where they recognised that there were a number of potentially valid approaches to wage adjustment which could be undertaken.

*"There is no single 'correct' method for making a wage adjustment to the costs of NIE and GB DNOs as part of benchmarking analysis. Some methods would use relatively detailed or granular wage data on the type of occupations that are relevant to NIE's business. But the sample size for this data is quite small and we have some concerns about its accuracy. However, if more aggregated data is used, there is a greater risk that estimation results are influenced by wage data for occupations that are not relevant to NIE's activities."*²⁶

- 5.79 The CC built upon this reasoning in its RP5 determination for NIE by producing econometric results from a range of different wage adjustment methods, rather than relying upon one single method. As a sense check, we have also ran a selection of alternative regional wage approaches in our pre-modelling adjustments, also provided by CEPA. This provides the Utility Regulator with a range of efficiency estimates and ensures that the Utility Regulator has been reasonable in considering sensitivities of the regional wage adjustment on the benchmarking results.

- 5.80 The next step of the process was to decide how the RWA should be applied to company cost data. We have considered the following two issues closely: calculating the quantum of labour costs to be adjusted, and adjusting for locally incurred costs.

i) Calculating the quantum of labour costs to be adjusted

- 5.81 The two sub-options to choose from are: using actual company labour costs; or using notional weightings applied to cost categories to determine labour costs. Based on CEPA advice, and following CC and Ofgem precedent, we have used a notional approach, which avoids any potential errors or bias in the information submitted by each individual company.

ii) Adjusting for locally incurred costs

- 5.82 Some labour costs, e.g. cost centres, can potentially be located outside of a company's operational area or can be imported from other areas. In theory, competitive pressures should therefore eliminate price differentials across regions. At RIIO-ED1, Ofgem accounted for this by applying a percentage to the amount of labour costs in each cost category that need to be carried out locally. However, the CC did not consider this at RP5, and instead applied the RWA to all indirect labour costs.
- 5.83 The Utility Regulator sought advice from CEPA on this issue. While recognising the logic behind Ofgem's approach, CEPA considered it difficult to pinpoint the total proportion of labour that can realistically be procured nationally by DNOs. Furthermore, CEPA were

²⁶ Paragraph 8.66 of CC RP5 Determination.
https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

unable to find the exact source of Ofgem's assumptions and, as a result, were unable to duplicate Ofgem's analysis. As a result, CEPA recommended, in the absence of further analysis, applying the regional labour adjustment to all labour costs to avoid potentially spurious accuracy.

- 5.84 On the 10 January 2017, NIE Networks and NERA sent the Utility Regulator a response to CEPA's RWA paper, which expressed their concerns with CEPA's recommendation with regards to the application of the RWA to all labour costs:

*"In addition to controlling for the fact that labour only represents a part of DNOs' total costs, it is also important to control for the fact that some categories of labour are effectively sourced from a national labour market. In essence, staff could be located anywhere in the country (or even abroad). Hence, DNOs in low-wage areas, like Northern Ireland, do not enjoy a cost savings relative to other DNOs for those employees. Applying the RLA to DNOs' entire labour share unfairly penalises those DNOs in low-wage regions and rewards DNOs in high-wage regions."*²⁷

- 5.85 We partially acknowledge NIE Networks' and NERA's concerns, and we therefore asked CEPA to produce model estimation results and efficiency estimates under different local labour sensitivities, described below. These results were provided by CEPA as sensitivities to their baseline modelling where no local labour adjustment was applied:

- i) **CEPA Baseline:** No local labour adjustment (i.e. apply RWA to all labour costs)
- ii) **Local labour sensitivity 1:** Apply Ofgem's RIIO-ED1 local labour adjustment to GB DNOs' and NIE Networks' costs.
- iii) **Local labour sensitivity 2:** Apply Ofgem's RIIO-ED1 local labour adjustment to GB DNOs' costs only.

- 5.86 The local labour sensitivities are discussed further in the sections below.

- 5.87 Further details on our regional wage adjustment approach are discussed in CEPA's regional wage paper, which is included in Annex A of this draft determination.

Modelling Approach

- 5.88 CEPA have advised the Utility Regulator on the best econometric models to use in the benchmarking of NIE Networks in RP6. CEPA's model development methodology followed an iterative process of model refinement that considered variations in the spectrum of costs assessed (i.e. the disaggregation of models) and the cost drivers used.

²⁷ NERA, 2017. Response to CEPA's Regional Labour Adjustment Approach. Prepared for NIE Networks. pp.10-11.

Disaggregation of models

5.89 CEPA's main focus has been on testing top-down and middle-up IMF&T and Indirect models, but they also tested more disaggregated models used by Ofgem at RIIO-ED1 (tree cutting and faults) and totex models:

- (i) Top-down IMF&T and Indirect models
- (ii) Middle-up models: network operating costs (NOCs), closely associated indirects (CAI), business support, load related capex and non-load related capex.
- (iii) Total capex models
- (iv) Totex models
- (v) Disaggregated models: tree cutting and faults.

Cost drivers

5.90 CEPA have tested the inclusion of different cost drivers that are often used to explain differences in costs across electricity distribution companies. These are described in the table below:

Drivers	Rationale
Customer numbers	Number of customers connected (i.e. connections). This is a scale variable as it is a measure of total consumer base.
Energy throughput	This is an output measure and related to both scale of network and network usage.
Network length	Total length of lines (not including dual circuits). This is a scale variable as it measures total network length.
Network density	Captures rural vs. urban divide.
Peak demand	This is a scale variable as it is a proxy for maximum system capacity. It is also an output variable as it is a measure of yearly peak demand.
Mean Equivalent Asset Value (MEAV)	Measures the overall size and complexity of the network
Composite scale variables (CSV)	Used by CC and Ofgem, these weight together various cost drivers together. CEPA use the CSV used by the CC at RP5, which applies a 50% weight to network length, a 25% weight to customer numbers, and a 25% weight to units distributed (or energy throughput).
Spans cut and spans inspected	Directly linked to the number of trees cut and inspected.
Total number of faults	Driver of fault expenditure.
MACRO CSV	Top-down totex cost driver used by Ofgem in RIIO-ED1. This is a CSV which places a weighting on MEAV and customer numbers. The weights are identified by running a regression of totex on MEAV and customer numbers.
Customer minutes lost & number of customer interruptions	Quality of service indicators capturing interruptions to end-customers.

Table 6: CEPA cost drivers

Estimation method

- 5.91 Following regulatory precedent set by Ofgem at RIIO-ED1 and CC at RP5, we selected pooled ordinary least squares (POLS) as our primary estimation method.
- 5.92 However, we also recognise the benefit in testing random effects models that recognise the panel structure of the data. Ofwat used this approach at PR14, and Ofgem tested this approach at RIIO-ED1 (albeit only using POLS to determine allowances).
- 5.93 As a result, CEPA have also ran models using random effects, and the results are published in CEPA's RP6 Efficiency Advice in Annex B to this draft determination.

Functional form of the cost function

- 5.94 CEPA have used Cobb-Douglas function forms in all of their final models but they also tested models with the inclusion of quadratic terms to allow for cost elasticities to vary across companies.
- 5.95 These models did not pass CEPA's model selection criteria and therefore are not included in the final set of models put forward in this draft determination.

Model selection criteria

- 5.96 To arrive at a set of preferred models, CEPA have taken the 'general-to-specific' approach to refine the set of viable cost drivers used in the models. Within this model refinement process, CEPA have applied a number of statistical diagnostic tests to ensure that the model specifications and estimation method are appropriate for the data being examined.
- 5.97 CEPA's model refinement process is summarised in the figure below, and more details are provided in CEPA's RP6 Efficiency Advice Paper in Annex B of this draft determination.

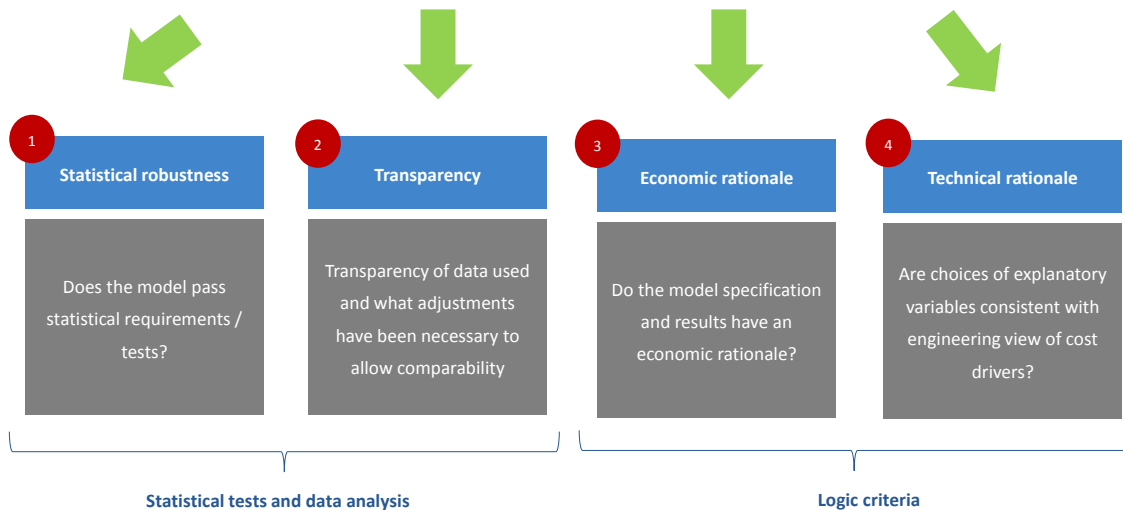


Figure 9: CEPA model selection criteria and estimation

- 5.98 The result of CEPA's model refinement process resulted in the list of potential cost drivers being refined to network length, network density, CSV and MEAV.
- 5.99 In the table below we present a set of three IMF&T and Indirect models we have selected from CEPA's analysis as our final set of IMF&T and Indirect Models for this draft determination. All three models have passed CEPA's model selection criteria on a pre- and post-allocation of indirect costs to connections basis, and under the three different local labour assumptions discussed above.

Model Number	Modelled cost	Cost Driver	Performance against selection criteria	
			Pre-allocation	Post-allocation
1	IMF&T and Indirects (CEPA Preferred)	Network length, Network density	Performs well	
2	IMF&T and Indirects (CC RP5 M4 Model)	CSV, time dummies	Performs well	
3	IMF&T and Indirects (CC RP5 M6 Model)	Length / customer numbers, time dummies	Performs well	

Table 7: RP6 Draft Determination Final IMF&T and Indirect Models

- 5.100 As mentioned in the data adjustments section, we estimate these models on a pre-allocation and post-allocation basis, and under three different local labour assumptions.²⁸

²⁸ i) No local labour adjustment; ii) Apply Ofgem's RIIO-ED1 local labour adjustment to all companies (i.e. Ofgem DNOs and NIE Networks); and iii) Apply Ofgem's RIIO-ED1 local labour adjustment to Ofgem GB DNOs only.

As a result, we have estimated each of the three final IMF&T and Indirect model specifications above six times.

- 5.101 An alternative approach to using total IMF&T and Indirect cost models is to run more disaggregated middle-up models such as NOCs, CAI and Business Support, which sum up to total IMF&T and Indirect costs. The potential benefit of this approach is that we are able to select cost drivers that better reflect these costs on a disaggregated basis than those chosen in the total IMF&T and Indirect models.
- 5.102 In the table below we have arrived at a preferred set of NOCs, CAI and Business Support models based on CEPA analysis, which we can use to derive a catch-up efficiency factor for IMF&T and Indirects.²⁹ Similarly, we have run these models on a pre- and post-allocation basis, and under the three local labour adjustments discussed above. All models pass CEPA's model selection criteria on a pre- and post-allocation basis, and across the three different local labour assumptions.

Model Number	Modelled cost	Cost Driver	Performance against selection criteria	
			Pre-allocation	Post-allocation
4	Network Operating Costs (NOCs)	Network length, Network density	Performs well	Performs well
5	Closely Associated Indirect Costs (CAI)	CSV, time dummies	Performs well	Performs well
6	Business Support Costs	Length / customer numbers, time dummies	Performs correctly, Marginally fails the RESET test.	Performs well

Table 8: RP6 Draft Determination NOCs, CAI and Business Support Models

- 5.103 As mentioned, CEPA also ran more disaggregated Ofgem models (tree cutting and faults), capex models, and totex models, but CEPA's and the Utility Regulator's focus has mainly been on IMF&T and Indirect cost models, as discussed above. As a result, model estimation results for these models are not presented here, but are presented in CEPA's RP6 Efficiency Advice Paper in Annex B of this draft determination.
- 5.104 At this point it is important to note that we have cognisance of Ofgem's approach to benchmarking at RIIO-ED1. However, Ofgem opted to take a totex approach to benchmarking at RIIO-ED1, which involved placing a 50% weight on totex econometric modelling and 50% weight on disaggregated bottom-up modelling.
- 5.105 After consideration, the Utility Regulator does not feel it is appropriate to use a totex approach to benchmarking and cost assessment at RP6 given that NIE Networks' capex requirements are likely to differ significantly from the capex requirements of GB DNOs.

²⁹ Utility Regulator's approach to triangulation across NOCs, CAI and Business Support models is detailed in below.

- 5.106 This was also the viewpoint of NERA, who provided efficiency advice on behalf of NIE Networks. As a result, while CEPA have run Ofgem's disaggregated tree cutting and faults model, we have decided to not rely on Ofgem's approach at RIIO-ED1 but instead use CEPA's independent model development to arrive at a preferred set of top-down and middle-up IMF&T and Indirect models, which are more appropriate for the benchmarking of NIE Networks with GB DNOs. This is different to the approach taken by NERA, on behalf of NIE Networks, who replicated Ofgem's disaggregated bottom-up benchmarking at RIIO-ED1 without undertaking any independent model development.
- 5.107 NERA's approach fails to gain an understanding of whether alternative models and modelling approaches may be more appropriate for NIE Networks. This is especially the case given additional historical data has become available since Ofgem conducted their RIIO-ED1 benchmarking, and cost allocations have also changed for some cost categories, for example, trouble call and asset replacement.
- 5.108 NERA have applied a 100% weight to Ofgem's disaggregated modelling while not attempting Ofgem's totex benchmarking, which Ofgem place a 50% weight on, recognising that it may not be appropriate to benchmark NIE Networks with GB DNOs with regards to capex. While the Utility Regulator agrees that capex benchmarking between NIE Networks and GB DNOs is not appropriate, as NERA have only used a certain proportion of Ofgem's benchmarking / cost assessment approach it is difficult to understand how NERA can claim they have followed Ofgem's approach at RIIO-ED1.
- 5.109 Furthermore, as highlighted in Ofgem's "*Strategy Consultation for the RIIO-ED1 electricity distribution price control – Tools for Cost Assessment*", using disaggregated modelling alone ignores the potential benefits of more aggregate top-down/middle up IMF&T and Indirect benchmarking. In particular, in contrast to disaggregated modelling, total IMF&T and Indirect cost modelling is not influenced by trade-offs between activities and reporting differences, and avoids 'cherry-picking' between different models.
- 5.110 Additionally, Ofgem's disaggregated modelling is mostly unit cost analysis, with econometric models run for tree cutting, faults and CAI. However, unit cost analysis may not suitably take into account the differences between GB DNOs and NIE Networks; and using the tree cutting, faults and CAI econometric models alone would not be sufficient to arrive at an overall IMF&T and Indirects level of efficiency for NIE Networks. Furthermore, Ofgem's faults and CAI models only covers a proportion of trouble call and CAI costs, which exacerbates the problem further. Moreover, the Ofgem fault model, which CEPA run as part of their analysis, failed the pooling test, which is an important part of CEPA's model selection criteria.
- 5.111 Taking these factors into account, we decided not to proceed with the disaggregated modelling approach adopted by NIE Networks / NERA. We do however acknowledge that disaggregated analysis can be useful in supporting, reinforcing and sense checking the findings from top-down benchmarking analysis. Taking this into account we have supported our top-down IMF&T and Indirects models with middle-up models for NOCs,

CAI and Business Support. We believe this approach appropriately manages the trade-offs between the aggregated and more disaggregated benchmarking analyses sufficiently.

IMF&T and Indirects modelling results

5.112 Shown in the tables and graphs below are CEPA's model estimation results for our three chosen IMF&T and Indirect cost models, on a pre- and post-allocation basis, and under the three different local labour assumptions described above.

5.113 We also present the following statistical diagnostic test results for each estimated model:

- i) **Ramsay RESET:** under this test, the null hypothesis is that there are no omitted non-linearities in the model. If we reject the null hypothesis then this is an indication that the model is mis-specified. CEPA place a relatively high weight on the outcome of this test in their model selection process.
- ii) **Normality test:** indicates whether the error term is normally distributed. CEPA place a low weight on the outcome of this test.
- iii) **Pooling test:** indicates whether the data is appropriate for pooling. If this test fails then this would be an indication that using panel data estimation methods is not appropriate.

5.114 The 2015 time dummies in models 3d, 3e and 3f, and the 2016 time dummies in models 2a-2f and 3a-3f, are the only parameter estimates that are not statistically significant at a 10% significance level. This is not detrimental to the model as this only means that the 2015 and/or 2016 model intercepts are not statistically significant from the 2013 intercept.

5.115 Furthermore, all estimated models presented pass all three of CEPA's statistical diagnostic tests with the exception of models 1b, 2b and 1c, where the null hypothesis that there are no non-linearities is rejected at a 10% significance level but not at a 5% significance level (Ramsay RESET). In alignment with CEPA's analysis, we consider this to only be a marginal fail, and therefore consider these models perform correctly.

5.116 Taking these into account, all models presented passed CEPA's model selection criteria. Further analysis of CEPA's IMF&T and Indirect cost model estimation results can be found in Annex B of this draft determination.

Table 9: Pre-allocation POLS IMF&T and Indirect model estimation results ³⁰

	No local labour adjustment			Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)			Ofgem Local Labour Adjustment (GB DNOs only)		
Model Number	Model 1a	Model 2a	Model 3a	Model 1b	Model 2b	Model 3b	Model 1c	Model 2c	Model 3c
Length	0.846***			0.843***			0.837***		
Density	0.449***			0.495***			0.470***		
CSV		0.858***			0.885***			0.867***	
Ln Length per Customer			0.559***			0.513***			0.538***
Time dummy (2014)		0.053***	0.048**		0.053***	0.048**		0.053***	0.048**
Time dummy (2015)		0.034**	0.024*		0.034**	0.024*		0.034**	0.024*
Time dummy (2016)		0.030	0.016		0.031	0.017		0.03	0.017
Constant	-5.922***	-5.019***	-7.588***	-6.047***	-5.337***	-7.754***	-5.900***	-5.117***	-7.662***
RESET	0.122	0.273	0.219	0.078	0.077	0.314	0.075	0.144	0.220
Normality Test	0.372	0.198	0.748	0.418	0.272	0.961	0.485	0.367	0.997
Pooling Test	0.928	1.000	1.000	0.851	1.000	1.000	0.842	1.000	1.000
N	60	60	60	60	60	60	60	60	60
R ²	0.846	0.835	0.69	0.882	0.873	0.7	0.879	0.871	0.722

³⁰ * indicates statistical significance at a 10% level; ** indicates statistical significance at a 5% level; *** indicates statistical significance at a 1% level. Estimated parameters in bold are not statistically significant. Statistical diagnostic test results in bold indicate that we reject the null hypothesis at a 5% significance level (i.e. the test fails). All explanatory and dependent variables are in natural logarithm.

Table 10: Post-allocation POLS IMF&T and Indirect model estimation results ³¹

	No local labour adjustment			Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)			Ofgem Local Labour Adjustment (GB DNOs only)		
Model Number	Model 1d	Model 2d	Model 3d	Model 1e	Model 2e	Model 3e	Model 1f	Model 2f	Model 3f
Length	0.888***			0.884***			0.880***		
Density	0.475***			0.518***			0.495***		
CSV		0.902***			0.927***			0.910***	
Ln Length per Customer			0.531***			0.488***			0.511***
Time dummy (2014)		0.070***	0.065***		0.071***	0.065***		0.071***	0.065***
Time dummy (2015)		0.041**	0.03		0.042**	0.031*		0.042**	0.031*
Time dummy (2016)		0.021	0.007		0.022	0.007		0.022	0.007
Constant	-6.581***	-5.638***	-7.807***	-6.700***	-5.939***	-7.963***	-6.562***	-5.731***	-7.876***
RESET	0.224	0.273	0.220	0.125	0.143	0.231	0.144	0.179	0.220
Normality Test	0.713	0.508	0.499	0.798	0.361	0.720	0.855	0.513	0.824
Pooling Test	0.924	1.000	1.000	0.863	1.000	1.000	0.844	1.000	1.000
N	60	60	60	60	60	60	60	60	60
R ²	0.800	0.790	0.592	0.836	0.828	0.598	0.837	0.83	0.629

³¹ * indicates statistical significance at a 10% level; ** indicates statistical significance at a 5% level; *** indicates statistical significance at a 1% level. Estimated parameters in bold are not statistically significant. Statistical diagnostic test results in bold indicate that we reject the null hypothesis at a 5% significance level (i.e. the test fails). All explanatory and dependent variables are in natural logarithm.

NOCs, CAI and Business Support disaggregated modelling results

- 5.117 The tables below present CEPA's model estimation results for the disaggregated NOCs, CAI and Business Support models CEPA developed through their independent development process, on a pre- and post-allocation basis, and under the three different local labour assumptions. We also present statistical diagnostic test results for each estimated model.
- 5.118 CEPA found network length and density to be the most appropriate drivers of NOCs. However, the density variable was not statistically significant for the CAI and Business Support models. As a result, CEPA chose the CSV as the single cost driver in the CAI and Business Support models. However, CEPA do note that using MEAV as the cost driver in the CAI and Business Support models is also credible and robust. But they decided on using a CSV because of two reasons:
- i) Regulatory precedent from CC RP5, who also used models with the same CSV.³²
 - ii) The MEAV has been created based on expert views of unit costs from Ofgem's RIIO-ED1 price control, and thus has some degree of discretion in how it is calculated. In contrast, while the weights of the CSV require discretion, their components have regulatory precedent and are individually reliable.
- 5.119 Based on CEPA's reasoning the Utility Regulator has decided to use the CSV as the cost driver in the CAI and Business Support models while acknowledging that using MEAV may also be credible and robust.
- 5.120 All parameter estimates presented below are sensible in magnitude and statistically significant at a 1% significance level. Furthermore, all estimated models pass CEPA's statistical diagnostic tests with the exception of model 6b (Business Support model, on pre-allocation basis, full local labour adjustment applied) where the null hypothesis that there are no non-linearities is rejected at a 5% significance level. This outcome indicates that there is a possibility that this model is mis-specified, and we therefore need to express some degree of caution when using this model. It is important to note that we also get this outcome when we use MEAV as the cost driver rather than the CSV in model 6b.
- 5.121 With the exception of model 6b, all other models on a pre- and post-allocation basis passed CEPA's model selection criteria. Further analysis of CEPA's NOCs, CAI and Business Support model estimation results can be found in Annex B of this draft determination.

³² The CSV applies a 50% weight to network length, a 25% weight to customer numbers, and a 25% weight to units distributed.

Table 11: Pre-allocation POLS NOCs, CAI and Business Support model estimation results ³³

	No local labour adjustment			Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)			Ofgem Local Labour Adjustment (GB DNOs only)		
Cost category	NOCs	CAI	Business Support	NOCs	CAI	Business Support	NOCs	CAI	Business Support
Model number	Model 4a	Model 5a	Model 6a	Model 4b	Model 5b	Model 6b	Model 4c	Model 5c	Model 6c
Length	1.067***			1.067***			1.066***		
Density	0.737***			0.747***			0.742***		
CSV		0.744***	0.586***		0.775***	0.634***		0.755***	0.603***
Constant	-10.402***	-4.535***	-3.390***	-10.435***	-4.894***	-3.952***	-10.402***	-4.661***	-3.583***
RESET	0.395	0.862	0.077	0.403	0.688	0.043	0.406	0.775	0.083
Normality Test	0.134	0.276	0.059	0.139	0.506	0.119	0.148	0.281	0.212
Pooling Test	0.981	0.669	0.994	0.978	0.569	0.993	0.978	0.601	0.993
N	60	60	60	60	60	60	60	60	60
R ²	0.737	0.757	0.622	0.746	0.798	0.667	0.745	0.782	0.651

³³ * indicates statistical significance at a 10% level; ** indicates statistical significance at a 5% level; *** indicates statistical significance at a 1% level. Estimated parameters in bold are not statistically significant. Statistical diagnostic test results in bold indicate that we reject the null hypothesis at a 5% significance level (i.e. the test fails). All explanatory and dependent variables are in natural logarithm.

Table 12: Post-allocation POLS NOCs, CAI and Business Support model estimation results³⁴

	No local labour adjustment			Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)			Ofgem Local Labour Adjustment (GB DNOs only)		
Cost category	NOCs	CAI	Business Support	NOCs	CAI	Business Support	NOCs	CAI	Business Support
Model number	Model 4d	Model 5d	Model 6d	Model 4e	Model 5e	Model 6e	Model 4f	Model 5f	Model 6f
Length	1.067***			1.067***			1.066***		
Density	0.737***			0.747***			0.742***		
CSV		0.793***	0.604***		0.824***	0.652***		0.804***	0.620***
Constant	-10.402***	-5.302***	-3.734***	-10.435***	-5.662***	-4.296***	-10.402***	-5.428***	-3.928***
RESET	0.395	0.760	0.225	0.403	0.628	0.191	0.406	0.742	0.221
Normality Test	0.134	0.994	0.135	0.139	0.949	0.293	0.148	0.978	0.250
Pooling Test	0.981	0.718	0.993	0.978	0.639	0.991	0.978	0.643	0.989
N	60	60	60	60	60	60	60	60	60
R ²	0.737	0.652	0.554	0.746	0.699	0.606	0.745	0.688	0.603

³⁴ * indicates statistical significance at a 10% level; ** indicates statistical significance at a 5% level; *** indicates statistical significance at a 1% level. Estimated parameters in bold are not statistically significant. Statistical diagnostic test results in bold indicate that we reject the null hypothesis at a 5% significance level (i.e. the test fails). All explanatory and dependent variables are in natural logarithm.

Efficiency gap analysis

- 5.122 In addition to providing model estimation results, we also asked CEPA to assess how NIE Networks perform in terms of efficiency for each model they estimated, and under different input sensitivities.
- 5.123 We asked CEPA to produce annual efficiency gaps for each year in the sample (2012/13 to 2015/16) but the Utility Regulator acknowledges that the average efficiency gap of the period being examined should also be considered since there can be some volatility between years. This is reflected in the Utility Regulator's approach to deriving a final catch-up efficiency factor that we apply to baseline costs (see section below on triangulation).
- 5.124 Under the Utility Regulator's advice, CEPA conducted their efficiency gap analysis by comparing the performance of NIE Networks with the fourth placed company in the sample (4 out of 15 companies), which is approximately equal to the upper quartile benchmark.³⁵ As a result, the efficiency gap is zero for the fourth placed company.
- 5.125 While the CC set the 5th placed company as the benchmark at RP5 they specified that this should not act as a limitation on future price controls.

*"Our choice of the cost benchmark reflects the specific circumstances of our inquiry and, in particular, the nature and limitations of the benchmarking analysis we have carried out. It also reflects the submissions made to us by parties in the course of our inquiry. It should not act as a constraint on the choice of cost benchmarks for any future price control reviews."*³⁶

- 5.126 Furthermore, regulatory precedent strongly suggests the use of a upper quartile benchmark or even more challenging benchmark. The upper quartile benchmark was adopted by Ofgem in RIIO-ED1 and RIIO-GD1 and by Ofwat in PR14. The Utility Regulator has adopted the upper quartile and frontier companies in its benchmarking of NI Water for capex and opex respectively, and also within its opex benchmarking of Northern Ireland's gas distribution companies (GDNs) for GD17.³⁷ Moreover, Monitor, the Regulator for health services, adopted the upper decile (90th percentile) in its assessment of the NHS Acute Sector; and Ofcom have benchmarked to upper decile in both the post and telecommunications sectors.³⁸
- 5.127 In addition, it should be noted that in the Utility Regulator's Corporate Strategy 2014-2019, we have set a Key Performance Indicator (KPI) for network utility costs and performance to measure favourably against the top quarter of appropriate comparable companies.³⁹ We believe this is a reasonable and achievable ambition for a company such as NIE Networks, in keeping with the Utility Regulator's *Strategic Objective 1 - promoting effective and efficient monopolies*.

³⁵ The upper quartile, or the 75th percentile, is equivalent to the 3.75 placed company. We have rounded this up to the 4th placed company for simplicity.

³⁶ Para 8.141 of CC RP5 determination.

³⁷ https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

³⁸ 3rd ranked company out of 8 GDNs in sample.

³⁹ See page 12 of Deloitte LLP Report on Econometric Benchmarking in UK Postal Sector:

<http://stakeholders.ofcom.org.uk/binaries/consultations/royal-mail-review/annexes/benchmarking-report.pdf>

³⁹ https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/UR_Corporate_Strategy_2014-2019.pdf

5.128 Taking this and the regulatory precedent into account, we consider the upper quartile, or 4th placed company, to be an appropriate benchmark to apply at RP6 and provides adequate scope for the company to out-perform during RP6.

5.129 The Utility Regulator has chosen to calculate the efficiency gap using the following approach:

- i) Run the model using POLS and obtain the predicted values for each DNO in each year.
- ii) Calculate the efficiency score for each DNO, which is calculated as actual costs divided by predicted costs.⁴⁰ An efficiency score greater than 1 indicates the company is inefficient relative to the average performing company. Conversely, an efficiency score less than 1 indicates the company is efficient relative to the average performing company.
- iii) Rank the efficiency scores in ascending order, and select the fourth lowest efficiency score, which is approximately the upper quartile benchmark.
- iv) The efficiency gap between NIE Networks and the fourth placed company is calculated as one minus the efficiency score of the fourth placed company divided by the efficiency score of NIE Networks. This is equivalent to the percentage change in NIE Networks' efficiency score required to reach the efficiency score of the fourth placed company:

$$\text{NIE Networks efficiency gap} = 1 - \frac{\text{Efficiency score of the fourth placed company}}{\text{Efficiency score of NIE Networks}}$$

- v) As a result, an efficiency gap of greater than 0% indicates NIE Networks is performing worse than the fourth placed company. Conversely, if the efficiency gap is less than or equal to 0%, this indicates that NIE Networks is performing better than or as the fourth placed company.

5.130 For brevity, we only present the efficiency gaps CEPA have derived for the models presented in this draft determination. Further efficiency gap analysis is presented in their RP6 Efficiency Advice Paper in Annex B to this draft determination.

Efficiency gaps: IMF&T and Indirect pre-allocation models

5.131 Presented below are the efficiency gaps CEPA have derived for IMF&T and Indirect cost models 1, 2 and 3 on a pre-allocation basis, under the three different local labour assumptions, and for each year in the data sample (2012/13 to 2015/16).

5.132 Generally, if we compare the efficiency gap over time, the efficiency gap is largest in 2015/16 and smallest in 2013/14:

- i) 2012/13 efficiency gap range: 5% to 14%.

⁴⁰ In this instance, when we refer to outturn costs we refer to normalised adjusted real costs that are used as an input into the modelling by CEPA. These are actual DNO costs in real terms once all of the relevant aforementioned cost adjustments have been made.

- ii) 2013/14 efficiency gap range: 0% to 5%.
- iii) 2014/15 efficiency gap range: 0% to 6%.
- iv) 2015/16 efficiency gap range: 6% to 15%.

5.133 Furthermore, if we compare the efficiency gap across the three different local labour assumptions, the efficiency gap tends to be smallest when we apply the local labour adjustment in full (i.e. GB DNOs and NIE Networks) and largest when we do not apply any local labour adjustment. When we only apply the local labour adjustment to GB DNOs, the efficiency gap falls in between the other two options.

	Model 1				Model 2				Model 3			
	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16
No Local Labour Adjustment	11%	4%	3%	15%	14%	5%	6%	14%	13%	4%	6%	12%
Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)	5%	0%	0%	10%	7%	0%	0%	8%	6%	1%	2%	6%
Ofgem Local Labour Adjustment (GB DNOs only)	10%	4%	4%	13%	13%	4%	4%	13%	10%	5%	6%	10%

Table 13: efficiency gaps - pre-allocation models

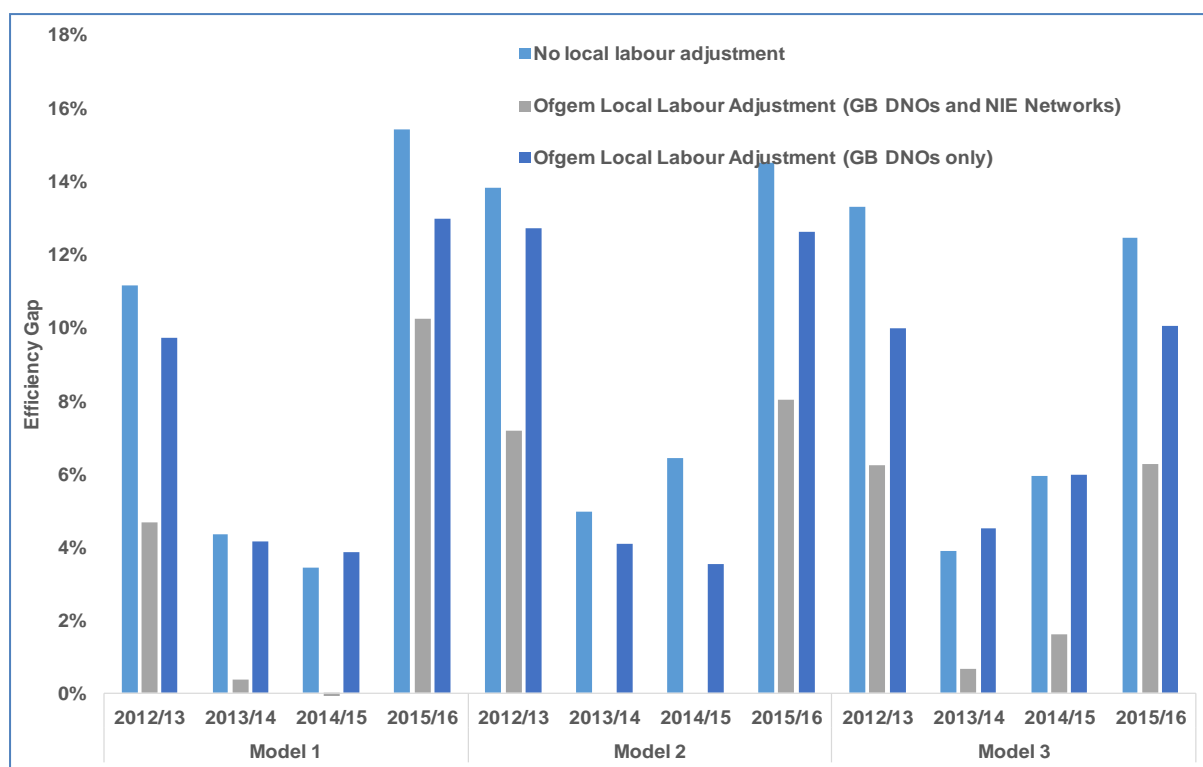


Figure 10: IMF&T and Indirect model efficiency gaps (pre-allocation)

Efficiency gaps: IMF&T and Indirect post-allocation models

- 5.134 Presented in the table and graph below are the efficiency gaps CEPA have derived for IMF&T and Indirect cost models 1, 2 and 3 on a post-allocation basis, under the three different local labour assumptions, and for each year in the data sample (2012/13 to 2015/16).
- 5.135 Generally speaking, NIE Networks' efficiency gap is smaller on a post-allocation basis than on a pre-allocation basis. This is likely to be because NIE Networks allocate a relatively larger proportion of indirects to connections than most GB DNOs.
- 5.136 When we compare the efficiency gap over time, the efficiency gap is generally largest in 2012/13 and smallest in 2014/15.
- 5.137 As we found in the pre-allocation models, the efficiency gap tends to be smallest when we apply the local labour adjustment in full (i.e. GB DNOs and NIE Networks) and largest when we do not apply any local labour adjustment.

	Model 1				Model 2				Model 3			
	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16
No Local Labour Adjustment	10%	-2%	-1%	7%	10%	-2%	0%	5%	10%	-1%	-2%	8%
Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)	2%	-6%	-9%	3%	11%	-1%	-2%	5%	9%	-1%	-3%	9%
Ofgem Local Labour Adjustment (GB DNOs only)	8%	-2%	-4%	7%	10%	-2%	-1%	5%	9%	0%	-4%	8%

Table 14: efficiency gaps - post-allocation models

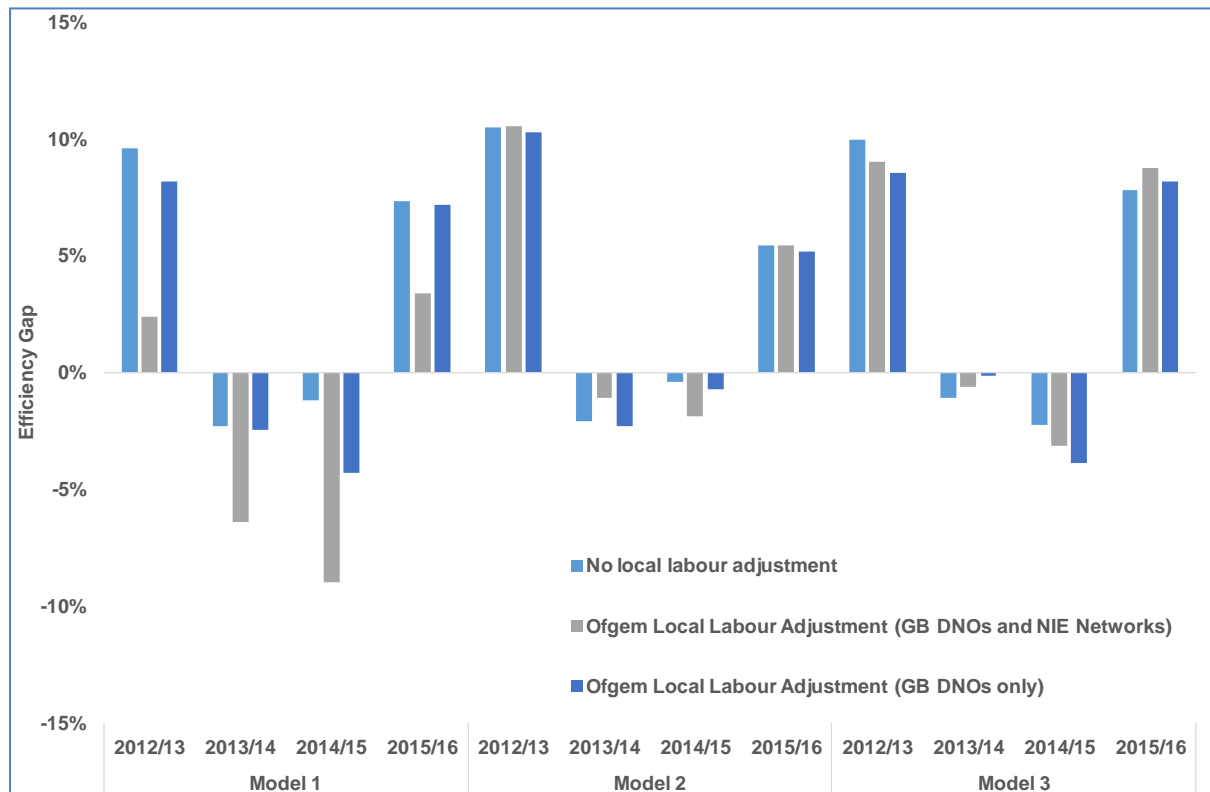


Figure 11: IMF&T and Indirect model efficiency gaps (post-allocation)

Efficiency gaps: NOCs, CAI and Business Support models

5.138 In combination, the NOCs, CAI and Business Support models cover the same costs as in our IMF&T and Indirect models. Hence, we can use the results of these models to gain an indication of what is causing the efficiency gaps from the IMF&T and Indirect models above.

5.139 The tables and charts below present NOCs, CAI and Business Support model efficiency gaps on a pre-allocation basis, under the three different local labour assumptions, and for each year in the data sample (2012/13 to 2015/16). Also shown are the equivalent efficiency gap data but on a post-allocation basis.

5.140 NIE Networks are relatively efficient in NOCs but are relatively inefficient in CAI and Business Support. As expected, NIE Networks generally appear more efficient in terms of CAI and Business Support on a post-allocation basis due to the fact they tend to allocate a relatively large amount of indirect costs to connections compared to other DNOs.

5.141 Furthermore, estimated efficiency gaps from the CAI and Business Support models are relatively more volatile over time than from the NOCs model. This is reflected in the ranges presented below:

- i) The NOCs efficiency gap on a pre- and post-allocation basis ranges from 0% to 2%.
- ii) The CAI efficiency gap ranges from 9% to 25% on a pre-allocation basis, and between -2% to 32% on a post-allocation basis.
- iii) The Business Support efficiency gap ranges from -2% to 18% on a pre-allocation basis, and ranges between -14% and 10% on a post-allocation basis.

	NOCs: Model 4				CAI: Model 5				Business Support: Model 6			
	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16
No Local Labour Adjustment	0%	0%	2%	2%	25%	21%	13%	18%	15%	3%	7%	11%
Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)	0%	0%	1%	1%	19%	17%	9%	16%	10%	-2%	-2%	8%
Ofgem Local Labour Adjustment (GB DNOs only)	0%	1%	2%	2%	24%	21%	13%	21%	18%	3%	5%	16%

Table 15: NOCs, CAI and Business Support model efficiency gaps (pre-allocation)

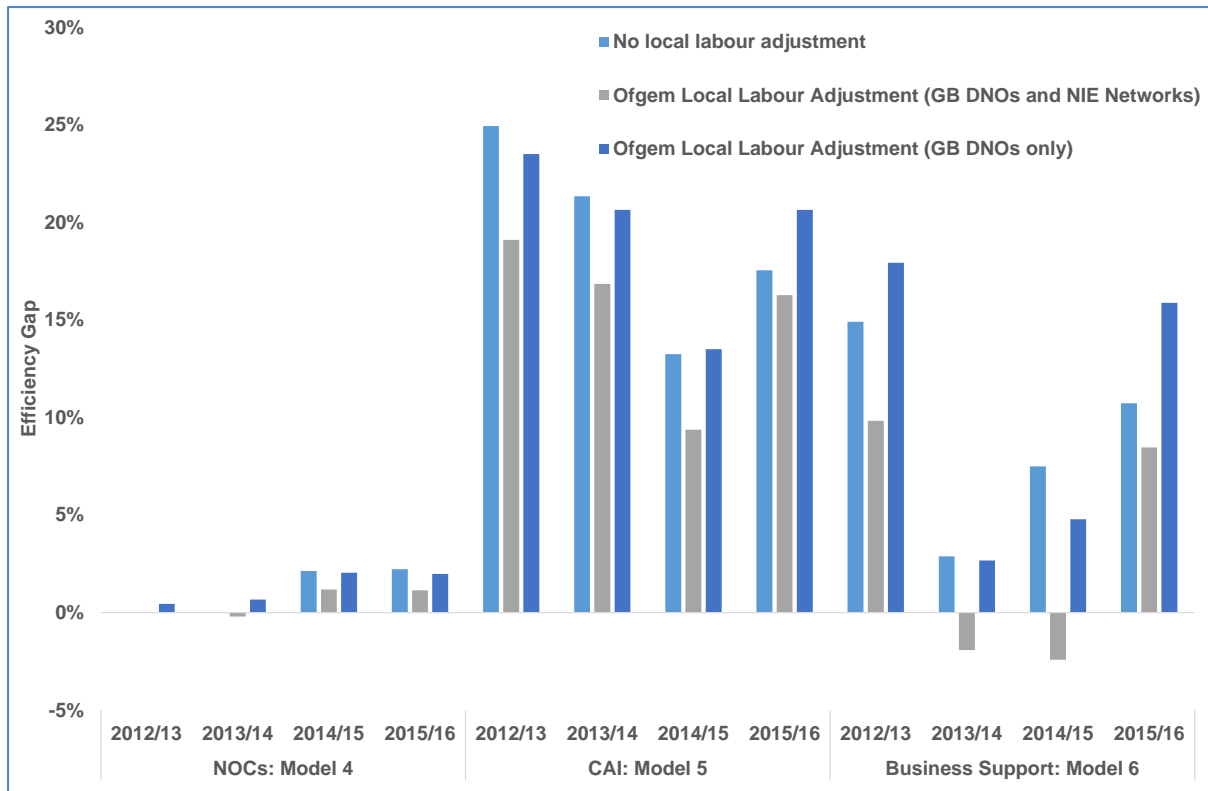


Figure 12: NOCs, CAI and Business Support model efficiency gaps (pre-allocation)

	NOCs: Model 4				CAI: Model 5				Business Support: Model 6			
	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16	2012 /13	2013 /14	2014 /15	2015 /16
No Local Labour Adjustment	0%	0%	2%	2%	32%	18%	3%	13%	10%	-5%	-6%	0%
Ofgem Local Labour Adjustment (GB DNOs and NIE Networks)	0%	0%	1%	1%	25%	13%	-2%	10%	3%	-12%	-14%	-1%
Ofgem Local Labour Adjustment (GB DNOs only)	0%	1%	2%	2%	29%	17%	3%	15%	10%	-3%	-7%	4%

Table 16: NOCs, CAI and Business Support model efficiency gaps (post-allocation)

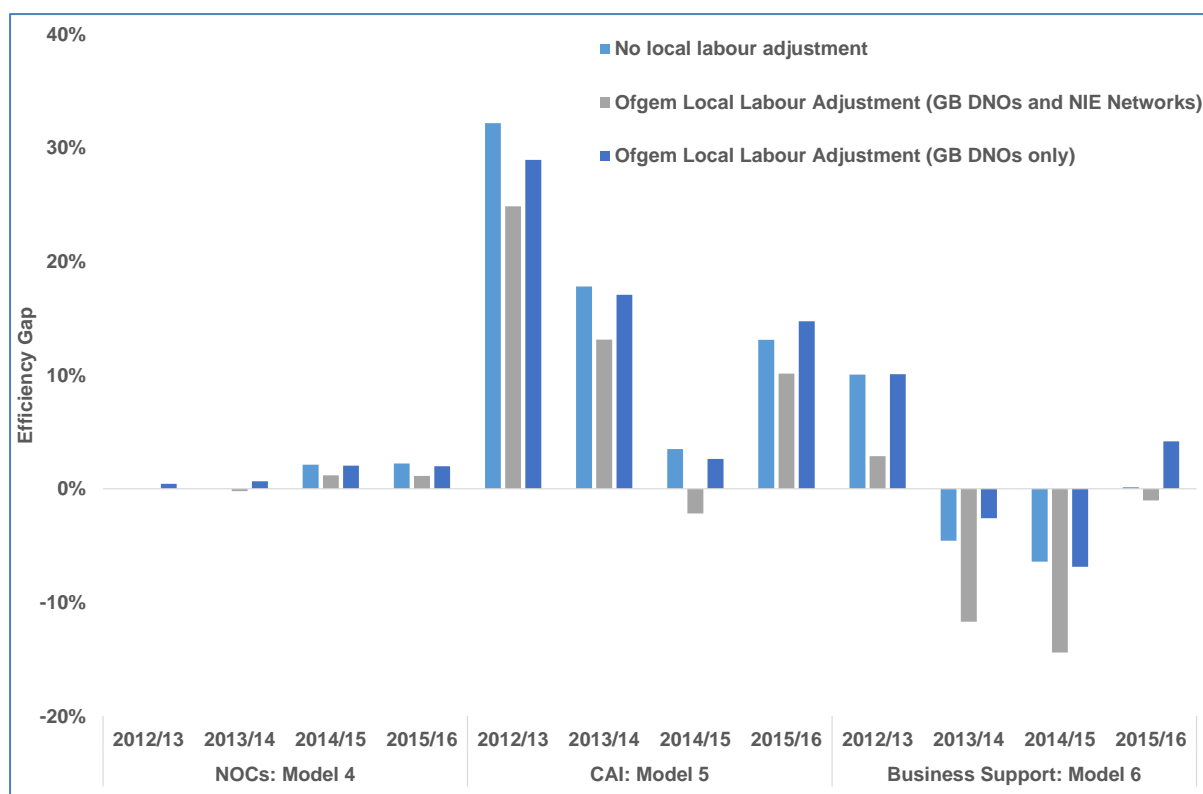


Figure 13: NOCs, CAI and Business Support model efficiency gaps (post-allocation)

Special factors

- 5.142 In reaching its modelling results for NIE Networks the Utility Regulator has not applied any special factor adjustments to NIE Networks' costs. Special factors are company specific circumstances, not taken into account in the data adjustments and model specifications, which cause costs to be materially different for that particular company relative to the comparator companies.
- 5.143 It should be noted that the CC did not apply any special factors during its RP5 modelling of NIE. It should also be noted that Ofgem applied a 'high hurdle' for company-specific factors in RIIO-ED1.⁴¹
- 5.144 The Utility Regulator in RP6 have built upon the CC approach and have not applied any special factors as yet. However, we keep an open mind as to whether special factors may apply for NIE Networks as we are aware that econometric models may not take into account all differences between companies, especially if these circumstances are unique. Respondents to the draft determination are therefore asked to consider whether they consider that there are any special factors that need to be applied with regards to the IMF&T and Indirect benchmarking models.
- 5.145 As stipulated to NIE Networks in its RP6 benchmarking guidance document⁴², the means by which the Utility Regulator shall assess the company's submission will include examination of each claim against the following criteria:

⁴¹ See paragraph 4.43 of RIIO-ED1: Final Determinations for the slow-track electricity distribution companies. https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_expenditure_assessment_0.pdf

- *What is different about the circumstances that cause materially higher cost claims which amount to greater than 1% of the total modelled costs in question?*
- *Why do these circumstances lead to higher costs?*
- *What is the net impact of these costs on prices over and above that which would be incurred without these factors? What has been done to manage the additional costs arising from the different circumstances and to limit their impact?*
- *Are there any other different circumstances that reduce the company's costs relative to industry norms? If so, have these been quantified and offset against the upward cost pressures?*

5.146 It should be noted that some special factors may only apply to certain models so respondents are asked to set special factors which are appropriate to each particular model and the cost categories being captured in the dependent variable.

5.147 In addition, a special factor may not apply (or only partially apply) if the model already takes into account the company specific factor(s) in question – i.e. within its model specification/ functional form or data adjustment.

5.148 Respondents are asked to provide workings of how they arrived at the special factor figures in their proposal and provide accompanying commentary substantiating their claim for the special factor, taking into account the assessment criteria above.

Future annual reporting and benchmarking

5.149 The Utility Regulator aims to undertake a relative efficiency analysis of NIE Networks after each reporting year of RP6 and report its findings in an annual Cost and Performance Report (CPR).

5.150 This report will be similar to the Utility Regulator's annual CPR for Northern Ireland Water,⁴³ as well as Ofgem's RII0-ED1 Annual Reports, which covers the performance of the 14 DNOs in Great Britain.⁴⁴

5.151 To facilitate this annual benchmarking, it is likely that in addition to its RIGs submission, a benchmarking data submission will also be required from NIE Networks after each reporting year.

5.152 Building upon the analysis undertaken in RP6, and any benchmarking undertaken in the annual CPR, it is likely that the Utility Regulator will undertake further relative efficiency analyses in the next electricity distribution price control of RP7.

⁴² https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/2016_02_17_Benchmarking_Efficiency_Data_Submission_-_Guidance_Notes_v0200_0.pdf

⁴³ <https://www.uregni.gov.uk/sites/uregni/files/media-files/Final%20Cost%20and%20Performance%20Report%20for%202015-16.pdf>

⁴⁴ https://www.ofgem.gov.uk/system/files/docs/2017/02/riio-ed1_annual_report_2015-16.pdf

Triangulation of model results

Introduction

- 5.153 The Utility Regulator acknowledges that NIE Networks' efficiency results are somewhat volatile across years, which may be caused by factors outside of the company's control such as the use of POLS as the primary econometric estimation method.
- 5.154 To take into account the volatility in efficiency across years, the average efficiency gap of the period being examined should also be considered.
- 5.155 We also consider it appropriate for the draft determination to triangulate across our set of preferred models (Models 1,2 and 3) and across different input assumptions, acknowledging that there is no perfect model or perfect set of input assumptions.
- 5.156 In the previous section we outlined the advantages and disadvantages of conducting benchmarking on a pre- and post-allocation of indirect costs to connections basis. Taking this into account, we consider it appropriate to triangulate across our preferred models (Model 1, 2 and 3) on a pre- and post-allocation basis.
- 5.157 We also consider it appropriate to triangulate across different local labour adjustments, which we discuss further below.
- 5.158 Taking these points into account, the Utility Regulator considers it appropriate to triangulate across Model 1, Model 2 and Model 3, and under the following data input assumptions:
- i) Pre-allocation of indirect costs to connections.
 - ii) Post-allocation of indirect costs to connections.
 - iii) Without Ofgem's local labour adjustment (CEPA Baseline).
 - iv) With Ofgem's local labour adjustment (Local labour sensitivity 1).
- 5.159 We consider this approach effectively and appropriately manages the trade-offs between conducting comparative benchmarking on a pre- or post-allocation of indirect costs to connections basis, and with or without the application of Ofgem's local labour adjustment.

Accounting for the proportion of labour that is located locally

- 5.160 CEPA in their regional wage adjustment (RWA) paper⁴⁵ recommended applying the regional labour adjustment to all labour costs to avoid potentially spurious accuracy.
- 5.161 However, we acknowledge NIE Networks' concerns with this approach with regards to how certain business support functions could in theory be located anywhere in the world. As a result, all DNOs could locate certain support services in the lowest cost

⁴⁵ See CEPA Regional Wage Adjustment paper in Annex A.

region of the world, meaning that DNOs in low-wage areas do not enjoy cost savings relative to other DNOs for these employees. If this assumption is truly correct, then applying the RWA to DNOs' labour costs that are not incurred locally would penalise those DNOs in low-wage regions and reward DNOs in high-wage regions.

5.162 Ofgem attempted to address this issue at RIIO-ED1 by only applying their RWA to a certain proportion of labour costs, which differed depending on the cost area being examined. The strongest assumptions were for business support costs, where Ofgem applied the RWA to 0% of business support labour costs, and closely associated indirect costs (CAI), where Ofgem applied the RWA to 40% of CAI labour costs.

5.163 While the Utility Regulator understands the logic behind Ofgem's approach, without having access to the detailed underpinning of how Ofgem have arrived at these percentages, we cannot be certain that these assumptions hold for a Northern Ireland based network utility. CEPA have raised a number of these factors in their RWA paper:

- i) There is likely to be an asymmetric effect. Companies operating in expensive areas would have incentives to acquire these services outside of their area, while those operating in cheaper areas are less likely to go to other markets where they would face higher costs.
- ii) The decision to relocate business support and CAI activities will not only be the result of differences in wages but there could be other considerations such as:
 - (i) the existence of cheaper regions inside of the area served by the DNO;
 - (ii) joint provision of services across DNOs in the same group;
 - (iii) political pressure to keep jobs in the area; and
 - (iv) degree of control required by the company over the provision of these services.

5.164 In addition, while labour costs will be an important factor in determining where DNOs locate certain support functions, the quality of service provided by different locations will also be a significant consideration. Especially considering that there is a customer service incentive in place in GB that encourages DNOs to manage the trade-off between costs and the quality of customer service effectively and appropriately. This incentive has the potential to persuade DNOs to locate their support services locally and potentially incur higher costs rather than simply locating their support services in the low cost region of the world.

5.165 These factors indicate that DNOs, may have limited incentive to obtain support services from the global market or even from the low cost labour region in the UK (i.e. Northern Ireland). This would reduce the adjustment required, and mean the Ofgem local labour adjustment applied at RIIO-ED1 is too strong for our modelling inputs.

5.166 This is evidenced when we consider where GB locate their customer service centres. All GB distributors appear to locate their customer service and new connection centres within the region they operate, and none appear to be located either in Northern Ireland or outside of the UK more generally.

- i) Scottish and Southern Electricity Networks – all customer service contact centres are GB based, with sites located in Perth (Scotland), Cumbernauld (Scotland), Cardiff (Wales) and Havant (South West England).⁴⁶
- ii) SP Energy Networks – both customer contact centres are located within their region. The first customer contact centre provides support to their customers in Scotland and is located in Kirkintilloch, Scotland. The second customer contact centre provides support to their customers in Merseyside, Cheshire, North Wales and North Shropshire and is located in Prenton, Merseyside. They also have two addresses to deal with customer connections queries which are also located locally.⁴⁷
- iii) Northern Power Grid – their customer contact is operational 24 hours a day and is located locally in Penshaw, Tyne and Wear. The company also has a customer connections contact centre located locally at Middlesbrough.⁴⁸
- iv) Electricity North West – customer contact centre is located locally in Warrington, Cheshire.⁴⁹
- v) Western Power Distribution – the company's information centre that deals with customer complaints is located locally in Bristol.⁵⁰ Furthermore, their new connections customer service teams are also located locally in Tipton (West Midlands), Swansea (South Wales) and Cornwall (South West).⁵¹
- vi) UK Power Networks – the company's customer care centre is located locally in Ipswich (East of England)⁵², and their head office is also located locally in London, which is the high cost region in the UK.⁵³

5.167 NIE Networks have informed the Utility Regulator that they locate 100% of their workforce (relating to IMF&T and Indirect) and 100% of their costs (relating to IMF&T and Indirect) within the region of Northern Ireland. This is not surprising given that Northern Ireland is a low cost region - there would not normally be a strong cost incentive to locate staff in a more expensive region of the UK.

5.168 Taking these factors into account the Utility Regulator considers that Ofgem's assumptions on the proportion of indirect labour costs that has to be incurred locally is too strong, and as a result we do not feel it is appropriate to apply Ofgem's local

⁴⁶ Source: <http://sse.com/careers/customerservice/>

⁴⁷ Source: https://www.spenenergynetworks.co.uk/pages/contact_us.aspx

⁴⁸ Source: <http://www.northernpowergrid.com/asset/0/document/1665.pdf>

⁴⁹ Source: <http://www.enwl.co.uk/docs/about-us/electricity-north-west-customer-strategy-brochure.pdf?sfvrsn=2>

⁵⁰ Source: <https://www.westernpower.co.uk/Contact-us/Complaints.aspx>

⁵¹ Source: <https://www.westernpower.co.uk/Connections/Contact-us.aspx>

⁵² Source: <http://www.ukpowernetworks.co.uk/internet/en/contact-us/>

⁵³ Source: <http://www.ukpowernetworksservices.co.uk/contact-us/>

labour assumption in full. In theory, and if cost was the only factor to consider, we recognise that DNOs would locate support services in the low cost regions of the world. But for the reasons outlined above, this is not the case in reality as there are many other factors that DNOs have to consider, and as a result often locate support services within the region they operate.

5.169 Therefore, rather than implement Ofgem's local labour assumption is full we propose to triangulate between benchmarking models where we apply Ofgem's local labour adjustment (Local labour sensitivity 1) and benchmarking models where we do not apply Ofgem's local labour adjustment (CEPA Baseline). We consider this approach is fair for customers and NIE Networks, and effectively balances the trade-off between theory and reality without requiring the Utility Regulator to make an arbitrary decision on the amount of support services that are located locally.

5.170 In a previous communication with NIE Networks we stated that we may triangulate between no local labour adjustment (CEPA Baseline) and where we only apply the local labour adjustment to GB DNOs (Local Labour Sensitivity 2).⁵⁴ However, we have decided to apply zero weight to models run under local labour sensitivity 2 for this draft determination.

Approach to combining efficiency across NOCs, CAI and Business Support models

5.171 In combination, NOCs, CAI and Business Support benchmarking models cover total IMF&T and Indirect costs. Hence, we can combine estimated efficiency from the NOCs, CAI and Business Support models to arrive at an overall IMF&T and Indirects efficiency estimate. We refer to this as our middle-up IMF&T and Indirects efficiency estimate.

5.172 As mentioned previously, we provide this middle-up IMF&T and Indirects efficiency estimate to support, reinforce and sense check the findings from our top-down IMF&T and Indirects benchmarking analysis.

5.173 When combining the results from the three models we have to take into account the weight of each cost category in total IMF&T and Indirect costs. This is reflected in our approach described below:

- i) Run NOCs, CAI and Business Support models and obtain predicted costs (in natural logarithm).
- ii) Take the exponential of predicted costs to reverse the natural logarithm transformation.
- iii) Sum up predicted costs from NOCs, CAI and Business Support models to obtain total IMF&T and Indirect predicted costs.
- iv) Calculate company efficiency scores and efficiency gaps as described above to obtain the Utility Regulator's middle-up IMF&T and Indirects efficiency estimate.

⁵⁴ Utility Regulator email to NIE Networks on the 10th February 2017.

Approach to averaging efficiency across time for each individual model

5.174 The Utility Regulator's approach to averaging efficiency across time for each individual model is described below:

- i) Run individual models and obtain predicted costs (in natural logarithm).
- ii) Take the exponential of predicted costs to reverse the natural logarithm transformation.
- iii) Sum up the predicted costs across time (2012/13 to 2015/16) and divide by the number of years in the sample (i.e. 4 years) to obtain average predicted costs across the historical period being assessed. Conduct the same procedure for outturn costs.⁵⁵
- iv) Calculate the efficiency scores and efficiency gaps, as described above.

5.175 The average efficiency gaps for Model 1, 2 and 3 under the different input assumptions we have discussed are presented in the table below.

⁵⁵ In this instance, when we refer to outturn costs we refer to normalised adjusted real costs that are used as an input into the modelling by CEPA. These are actual DNO costs in real costs once all of the relevant aforementioned cost adjustments have been made.

		Weighted time average (2012/13 to 2015/16)			
		No local labour adjustment	Full local labour adjustment	No local labour adjustment	Full local labour adjustment
Model	Drivers	Pre allocation		Post allocation	
1	Length, Density	7.91%	0.28%	1.16%	-1.76%
2	CSV, time dummies	10.63%	1.72%	3.33%	-2.37%
3	Length/customers, time dummies	8.10%	1.40%	5.84%	0.01%
Middle -up		9.30%	2.15%	3.24%	2.61%
<i>NOCs</i>	<i>Length and density</i>				
<i>CAI</i>	<i>CSV</i>				
<i>Business Support</i>	<i>CSV</i>				

Table 17: Weighted time average efficiency gaps across different options

- 5.176 The middle-up IMF&T and Indirect efficiency gaps; obtained by combining the results from the NOCs, CAI and Business Support models; fall within the range of efficiency gaps obtained from Models 1, 2 and 3. This gives us additional confidence in the IMF&T and Indirect models CEPA and the Utility Regulator have selected.
- 5.177 While these individual results are helpful in providing an indication of how the efficiency gap differs depending on the model and/or input assumptions chosen, it is necessary to triangulate across these different options to arrive at an overall catch-up efficiency factor that we apply to base year IMF&T and Indirect costs.
- 5.178 The Utility Regulator's approach to triangulation across the different options is presented below. It is important to note that it is not appropriate to simply take the arithmetic average of the different efficiency gaps presented in the table below does not take into account:
- The weights the Utility Regulator has chosen to apply to the different options.
 - The underlying data differences between the different options that we need to take into account before triangulation to ensure we are comparing like-for-like.

		Weighted time average (2012/13 to 2015/16)			
		No local labour adjustment	Full local labour adjustment	No local labour adjustment	Full local labour adjustment
Model	Drivers	Pre allocation		Post allocation	
1	Length, Density	7.91%	0.28%	1.16%	-1.76%
2	CSV, time dummies	10.63%	1.72%	3.33%	-2.37%
3	Length/customers, time dummies	8.10%	1.40%	5.84%	0.01%
Middle -up		9.30%	2.15%	3.24%	2.61%
NOCs	Length and density				
CAI	CSV				
Business Support	CSV				

Table 18: Approach to triangulation across different options

5.179 The Utility Regulator has taken the following approach to obtain an overall catch-up efficiency factor when triangulating across different options:

- i) Run individual models and obtain predicted costs (in natural logarithm) for each year in the sample (2012/13 to 2015/16).
- ii) Take the exponential of predicted costs to reverse the natural logarithm transformation.
- iii) Multiply predicted costs from Model 3 by customer numbers to obtain total predicted IMFT and Indirect costs, for each year in the data sample.⁵⁶
- iv) Sum up predicted costs from the NOCs, CAI and Business Support middle-up models to obtain total predicted IMFT and Indirect costs, for each year in the data sample.
- v) Sum up predicted IMFT and Indirect costs across time (2012/13 to 2015/16) for each model, and divide by the number of years in the sample to obtain the average over the period (i.e. 4 years).
- vi) Multiply the predicted costs from the pre-allocation models by the ratio of “time average normalised adjusted real IMF&T and Indirect costs on a post-allocation basis” and “time average normalised adjusted real IMF&T and Indirect costs on a pre-allocation basis”. This ensures that all predicted IMF&T and Indirect costs we are comparing are on a like-for-like post-allocation

⁵⁶ Model 3 is a unit cost regression model, and the dependent variable is IMF&T and Indirects per customer.

basis. This ratio can differ depending on the company being examined and the local labour adjustment applied (i.e. no local labour adjustment (CEPA Baseline) or full local labour adjustment (Local Labour Sensitivity 1)).

- vii) Sum up outturn IMF&T and Indirect costs across time (2012/13 to 2015/16) on a post-allocation basis, and divide by the number of years in the sample to obtain the average over the period (i.e. 4 years).⁵⁷
- viii) Multiply the predicted costs from each option by each respective weight chosen by the Utility Regulator, ensuring the weights add up to one. The weights we have chosen for this draft determination are presented in the table below.
- ix) Sum up the weighted predicted costs to obtain total predicted IMFT and Indirect costs on a post allocation basis.
- x) Calculate the efficiency score for each company by dividing “average outturn IMF&T and Indirect costs on a post-allocation basis” by “weighted average predicted IMF&T and Indirect costs on a post-allocation basis”.⁵⁸ We then obtain the triangulated catch-up efficiency factor using the approach described above.

Utility Regulator Model Weights		No local labour adjustment	Full local labour adjustment	No local labour adjustment	Full local labour adjustment
Model Number	Drivers	Pre allocation		Post allocation	
1	Length, Density	8.33%	8.33%	8.33%	8.33%
2	CSV, time dummies	8.33%	8.33%	8.33%	8.33%
3	Length/customers, time dummies	8.33%	8.33%	8.33%	8.33%

Table 19: Utility Regulator chosen model weights

5.180 Using this approach we arrive at a triangulated catch-up efficiency factor of approximately 2.0%.⁵⁹

⁵⁷ In this instance, when we refer to outturn costs we refer to normalised adjusted real costs that are used as an input into the modelling by CEPA. These are actual DNO costs in real costs once all of the relevant aforementioned cost adjustments have been made.

⁵⁸ In this instance, outturn costs on a post-allocation basis refer to normalised adjusted real costs that are used as an input into the modelling by CEPA after allocating a proportion of indirect costs to connections.

⁵⁹ To two decimal places the catch-up efficiency factor applied is 1.96%.

Unit cost comparisons (distribution)

- 5.181 As indicated in our RP6 Final Approach Document and our RP6 Benchmarking & Efficiency Data Submission Guidance Notes we have undertaken unit cost analysis in addition to comparative benchmarking.⁶⁰ This compares NIE Networks to the 14 GB DNOs on a per customer, per unit of electricity distributed and per length of line basis across a range of aggregated and disaggregated costs. We also examined unit costs for tree-cutting on a workload basis (i.e. per spans cut).
- 5.182 However, while unit cost analyses can be informative, they would not typically be regarded as sophisticated as econometric analysis which can take into account economies of scale considerations etc. As a result, we have used our unit cost analysis as a sense check to our comparative benchmarking but not to inform the resulting catch-up efficiency factor we apply to NIE Networks base IMF&T and Indirect expenditure.
- 5.183 Taking this into account, we consider that the unit cost results concur with the findings of the top-down benchmarking (IMFT and Indirect models) and the middle-up models (NOCs, CAI and Business Support).

Transmission IMF&T and Indirects Benchmarking

- 5.184 CEPA's benchmarking included IMF&T and Indirect costs associated with NIE Networks' 132kV transmission network. Hence, we only have to consider how to deal with IMF&T and Indirect costs associated with NIE Networks' 275kV transmission network.
- 5.185 The Utility Regulator asked CEPA for advice on assessing options for benchmarking electricity transmission IMF&T and Indirect expenditure. In particular, the Utility Regulator aimed to evaluate whether it was viable to conduct international benchmarking in transmission. CEPA concluded that international benchmarking of transmission IMF&T and Indirects was not viable at RP6. It is fair to say that there is only a small number of transmission comparator companies in Great Britain, with which to potentially benchmark NIE Networks against.
- 5.186 Taking CEPA's recommendation into account we have not undertaken benchmarking of NIE Networks' transmission IMF&T and Indirect costs. The Utility Regulator has decided that the most pragmatic approach is to apply the resulting triangulated catch-up efficiency factor from our comparative benchmarking analysis (110kV or less) to IMF&T and Indirect base costs (2015/16) associated with the NIE Networks' 275kV network. Given that NIE Networks operate as one business we consider this is the appropriate approach to take.
- 5.187 The underlying principles of this approach was undertaken by the CC in their RP5 determination.

⁶⁰ Not presented in this draft determination due to data confidentiality.

IMF&T and Indirects RP6 allowance

- 5.188 To obtain the IMF&T and Indirect expenditure allowance for NIE Networks during RP6 we have applied the triangulated catch-up efficiency factor of approximately 2.0% as a P_0 adjustment to NIE Networks' base IMF&T and Indirect costs (2015/16). As mentioned previously, this includes IMF&T and Indirect expenditure relating to distribution and transmission, i.e. covers total NIE Networks' IMF&T and Indirect expenditure.
- 5.189 This approach was explicitly detailed in the Utility Regulator's RP6 approach document and Benchmarking & Efficiency Data Submission Guidance document (February 2016) and the Utility Regulator's associated workbook.

*"In the Utility Regulator's Approach to RP6 document, it was outlined how we expect NIE Networks to provide information which would enable the benchmarking of NIE Networks' costs against peer enterprises operating in the rest of the UK and Europe. If NIE Networks' costs are higher than the benchmark company(s), we will consider applying catch-up efficiency factors to the firm's baseline costs."*⁶¹

- 5.190 The approach of applying efficiency results to a base year is standard in RPI +/- X regulation and was followed by the Utility Regulator in PC10, PC13, and PC15 where we applied findings from our econometric and unit cost results to NI Water's base opex. The principle was also adopted by the CC in its RP5 of NIE, where the CC applied its efficiency model results to a base year's costs (namely 2011/12) to derive its RP5 allowance:

"..... we took the following approach for our final determination:

*"(a) For indirect and IMF&T costs, our RPE and productivity estimate was from 2011/12 until the end of our revenue control. This was because we set an efficient allowance for NIE's indirect costs based on benchmarked GB DNO cost data from 2011/12 (see paragraphs 8.30 to 8.36). This benchmarked allowance represented an estimate of the indirect costs of an efficient firm in 2011/12....."*⁶²

- 5.191 The CC also indicated at RP5 that 2015-16 would be the base year for RP6, when they discussed the introduction of the RIGs reporting regime for NIE. According to the CC, a 2015-16 base year would be beneficial as it would mark a more accurate set of reported information than an earlier year:

"We found that the availability of RIGs reporting in 2015/16, the base year for the next price control, was very important and in the public interest. We considered it was important that both NIE and the Utility Regulator had one

⁶¹ https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/2016_02_17_Benchmarking_Efficiency_Data_Submission_-_Guidance_Notes_v0200_0.pdf

⁶² From paragraph 11.8 of CC RP5 determination:
https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

year of exposure to RIGs reporting before the base year, even if that first year of reporting (2014/15) had a number of areas with low confidence grading or had some gaps, which would be agreed with the Utility Regulator.”⁶³

- 5.192 NIE Networks’ base 2015/16 IMF&T and Indirect costs were taken from NIE Networks’ Financial Data RIGs, submitted as part of the company’s RP6 submission to the Utility Regulator. The only difference between 2015/16 IMF&T and Indirect costs reported in NIE Networks’ C1 Matrix⁶⁴ and NIE Networks’ Financial Data RIGs is the classification of STEPM, which is classified as non-op capex in the C1 Matrix but as CAI in the Financial Data RIGs.
- 5.193 Various additional IMT&T and Indirect costs were identified by NIE Networks within its RP6 Business Plan (for cost increases associated with ESQCR, IT opex costs for enhanced Network Management System Infrastructure, and increases in tree-cutting expenditure in the low voltage network) alongside a limited number of instances where such operational costs were expected by the company to reduce over the RP6 period. Compared to the 2015/16 base year, NIE Networks have forecasted IMF&T and Indirect costs to be approximately £5.7 million (in 2015/16 prices) higher on average per annum through RP6. The Utility Regulator considers that these additional costs are not justified on the basis they mirror such costs already incurred by comparator DNOs in GB.
- 5.194 For example, the comparator data upon which the benchmarking was performed (i.e. GB DNOs) operate to a 12 hour guaranteed standards of service requirement for RIIO-ED1 which DNOs must meet - this improved from a 18 hour standard in DPCR5. If GB DNOs fail to meet this standard they are required to make payments to customers. However, NIE Networks currently operate to restore 100% of customers who lose power supply within 24 hours. We have proposed that the guaranteed standards of service requirement is improved to 18 hours by the end of the RP6 period. This proposal is in line with Ofgem at DPCR5 but avoids a significant improvement to a 12 hour standard set by Ofgem at RIIO-ED1.
- 5.195 While this change in NIE Networks’ guaranteed standards of service requirements may result in additional costs for NIE Networks during RP6 relative to RP5, GB DNO costs used in the benchmarking data set will reflect higher costs associated with operating to a higher standard compared to NIE Networks (i.e. 12/18 hour standard versus a 24 hour standard).
- 5.196 This may have warranted a data/special factor adjustment to make GB DNO costs more comparable with NIE Networks (i.e. increase in NIE Networks costs or decrease in GB DNO costs), which would result in the widening of NIE Networks’ efficiency gap. However, at this draft determination we have not made this adjustment, and as a result the efficiency gap we apply to NIE Networks base IMF&T and Indirect costs is less significant in terms of magnitude than it perhaps could be.

⁶³ From paragraph 18.75 of CC RP5 determination:
https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

⁶⁴ Submitted to the Utility Regulator as part of NIE Networks’ RP6 business plan submission, and subsequently used in the comparative benchmarking analysis.

5.197 The same reasoning is true for not allowing other additional IMF&T and Indirect cost claims during RP6 by NIE Networks. We summarise our reasoning for not allowing IMF&T and Indirect RP6 additions as presented by NIE Networks in the table below.

Table 20: RP6 IMF&T and Indirect cost additions proposed by NIE Networks (relative to a 2015/16 base year)

RP6 Additions	NIE Networks' reasoning	Criteria met?	Comment
Distribution Tree cutting (non-ESQCR)	An increase in requirements to address tree cutting on the low-voltage network.	No	<p>LV tree cutting would result in the company meeting higher standards, towards GB comparator equivalent service standard.</p> <p>GB comparators are already incorporated within our benchmarking and justify the 2015/16 base roll forward (minus P_0 adjustment for catch-up efficiency).</p> <p>We deem the company is adequately funded in RP6 without the need for an addition to our IMF&T and Indirect cost allowance.</p>
Engineering management and clerical costs (CAI)	<p>Forecast to increase in RP6 compared to RP5, as a result of increases in the scale and scope of specific aspects of the overall capex plan, particularly in respect of the ESQCR programme and innovation work.</p> <p>As a large element of the ESQCR programme will be delivered through third party providers, NIE Networks will require additional internal project and contract management resources. The successful delivery of these additional programmes requires additional engineers, team managers and support staff.</p>	No	<p>ESQCR and innovation are already included within GB comparator equivalent activities.</p> <p>GB comparators are already incorporated within our benchmarking and justify the 2015/16 base roll forward (minus P_0 adjustment for catch-up efficiency).</p> <p>We deem the company is adequately funded in RP6 without the need for an addition to our IMF&T and Indirects allowance.</p>

Project Management	<p>Forecast to increase in RP6 as a result of increases in the overall capex programme, particularly the ESQCR programme and innovation schemes.</p> <p>NIE Networks have also proposed a number of additional innovation projects including smart asset monitoring, demand side response and voltage management which will require additional project managers for the first three and a half years of RP6.</p>	No	As above.
Network Design and Engineering	Additional resource requirements to deliver the increased capex plan and the ESQCR programme.	No	Same as above.
IT and telecoms operational costs	<p>NIE Networks are forecasted to increase over the RP6 period compared to RP5 due to additional hardware support and associated operating system licence costs.</p> <p>This is a result of an enhanced Network Management System infrastructure; the introduction of additional IT security devices to protect the network; and an increase in the population of mobile devices.</p>	No	<p>IT and telecoms operational spending is already included within GB comparator equivalent activities.</p> <p>GB comparators are already incorporated within our benchmarking and justify the 2015/16 base roll forward (minus P₀ adjustment for catch-up efficiency).</p> <p>We deem the company is adequately funded in RP6 without the need for an addition to our IMF&T and Indirects allowance (both 'top-down' and 'middle-up' models, specifically Business Support Costs).</p>

Property and Management	No valid or reasonable justification provided with NIE Networks' business plan.	No	Same as above
Finance and Regulation	<p>NIE Networks claim that due to lower staff costs and lower company overheads finance and regulation costs are forecast to be lower in RP6 relative to RP5. However, compared to a 2015/16 base year, this does not seem the case.</p> <p>Costs in 2022/23 are forecast to increase for that year only by approximately £1.1 million, owing to the additional resource needed in our regulation and finance functions for the development of RP7.</p>	No	<p>Finance and regulation operational spending is already included within GB comparator equivalent activities.</p> <p>GB comparators are already incorporated within our benchmarking and justify the 2015/16 base roll forward (minus P₀ adjustment for catch-up efficiency).</p> <p>We deem the company adequately funded in RP6 without the need for any offsetting decrement to our IMF&T and Indirects amounts.</p>
Residual	<p>Due to additional costs compared to a 2015/16 base year.</p> <p>No explanation has been provided by NIE Networks as to why their RP6 forecasts are higher than the equivalent costs incurred in 2015/16.</p> <p>Costs include: CEO, Control Centre and Operational Training.</p>	No	No justification for increase provided by NIE Networks.

- 5.198 Furthermore, the Utility Regulator decided not to include STEPМ in the benchmarking exercise as we considered it was difficult to compare STEPМ across DNOs. However, we do consider it appropriate to apply the triangulated catch-up efficiency factor to STEPМ base costs. As a result, we leave STEPМ expenditure in NIE Networks' base 2015/16 IMF&T and Indirect costs taken from the Financial RIGs data. Hence, there is no requirement to produce a separate assessment of STEPМ base expenditure for RP6.
- 5.199 However, atypical severe weather, rates, pension deficit costs and non-op capex IT and Telecoms are excluded and are assessed separately.
- 5.200 The Utility Regulator considers that it has set a challenging but achievable target for NIE Networks in this RP6 draft determination. Although 2.0% catch-up is a relatively small percentage figure, it should be noted that this target is in conjunction with a 1.0% per annum productivity figure as detailed in the Frontier Shift section within Chapter 10 (frontier shift for RP6 not shown on the graph below).
- 5.201 Notwithstanding, although the target represents some challenge for the company, it is the Utility Regulator's considered view that scope remains for NIE Networks to outperform the RP6 allowances on IMF&T and Indirects.
- 5.202 The chart below presents NIE Networks' IMF&T and Indirect allowance for RP6.⁶⁵ RP5 allowances, RP5 outturns and NIE Networks' own RP6 IMF&T and Indirect forecasts are also presented for comparison purposes.
- 5.203 RP5 allowances are presented on a post productivity and RPEs basis to enable a comparison with RP5 outturn data between 2012/13 and 2015/16. Whereas, both the Utility Regulator's draft determination allowance and NIE Networks' IMF&T and Indirect forecasts from 2016/17 onwards are presented on a pre productivity and RPEs basis. Our assumptions regarding productivity and RPEs are presented in Chapter 10 of this draft determination.
- 5.204 In addition, we also present a table which compares NIE Networks IMF&T and Indirect cost forecasts during RP6 with the Utility Regulator's IMF&T and Indirects allowance during RP6. We have disaggregated NIE Networks' forecasts into base IMF&T and Indirect costs (2015/16) and new RP6 IMF&T and Indirect costs that NIE Networks have proposed.⁶⁶ The difference between 2015/16 base IMF&T and Indirect expenditure and the Utility Regulator's RP6 allowance is due to our catch-up efficiency factor of approximately 2.0%, which is also set out in the table.

⁶⁵ Distribution plus transmission IMF&T and Indirect expenditure, including tree cutting.

⁶⁶ 2017/18 only relates to the second half of the year (i.e. 1 October 2017 to 31 March 2018).

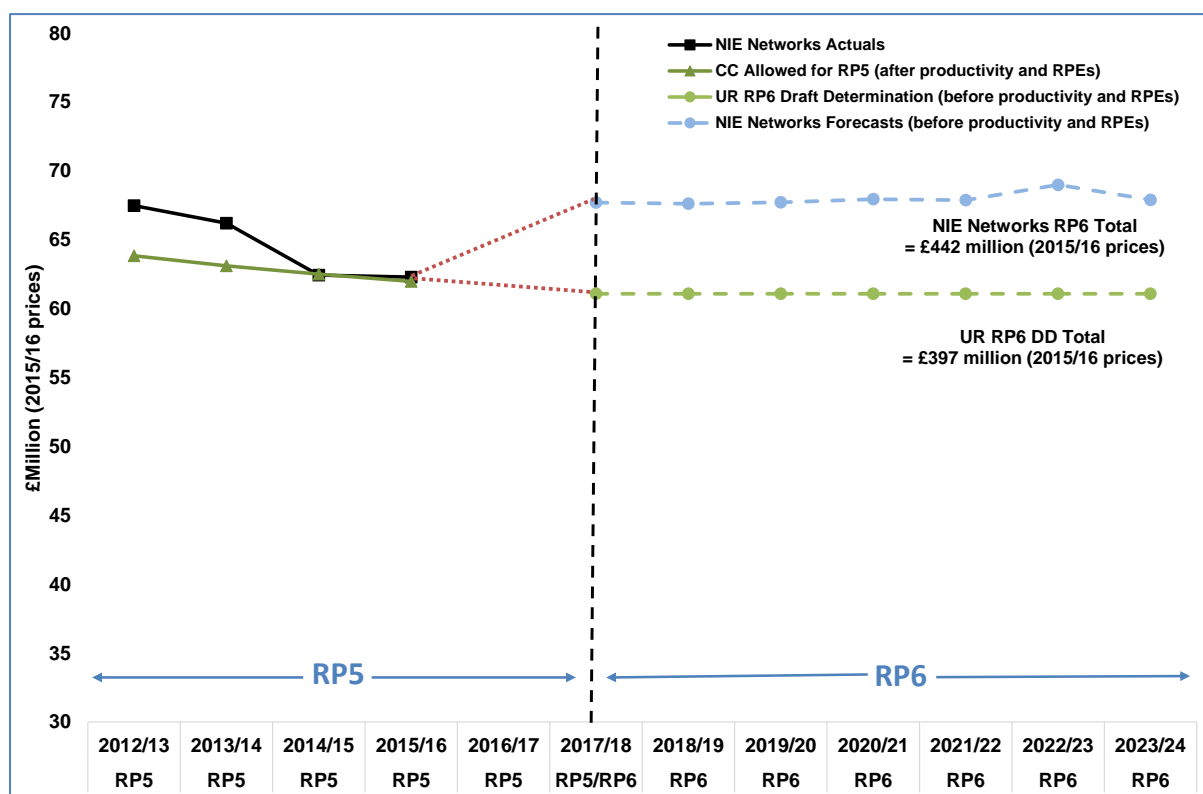


Figure 14: RP6 IMF&T and Indirects allowance at draft determination (pre RPEs and productivity)

RP6 Comparison (£million in 2015/16 prices)	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022	2022/ 2023	2023/ 2024
NIE Networks RP6 forecasts	33.923	67.623	67.722	67.954	67.881	68.987	67.900
2015/16 base IMF&T and Indirects	31.149	62.299	62.299	62.299	62.299	62.299	62.299
RP6 additions	2.773	5.324	5.423	5.655	5.583	6.688	5.601
Utility Regulator catch-up efficiency (on 2015-16 base)	0.611	1.223	1.223	1.223	1.223	1.223	1.223
Utility Regulator allowance after catch-up efficiency	30.538	61.076	61.076	61.076	61.076	61.076	61.076
Difference between Utility Regulator allowance and NIE Networks' forecasts	3.384	6.547	6.646	6.877	6.805	7.911	6.823
% Difference between Utility Regulator allowance and NIE Networks' forecasts	-9.98%	-9.68%	-9.81%	-10.12%	-10.02%	-11.47%	-10.05%

Table 21: RP6 IMF&T and Indirects Allowance - Pre Productivity and RPEs

6 Other Operating Costs

Severe Weather Allowance

Introduction

6

- 6.1 We consider that costs associated with atypical severe weather costs are somewhat outside of NIE Networks' control and are by definition not incurred every year by every DNO. Hence, CEPA did not include expenditure attributable to atypical 1-in-20 severe weather events within their benchmarking of NIE Networks' IMF&T and Indirect costs.
- 6.2 It is therefore required that we conduct a separate assessment on the level of costs associated with 1-in-20 atypical severe weather events that should be allowed during RP6. This was the approach taken by CC at RP5.
- 6.3 Ofgem defines a 1-in-20 atypical severe weather event as an event that gives rise to more than 42 times the mean incidents at HV and above. Therefore, the threshold is specified separately for each company. Any costs associated with severe weather that do not meet this threshold are included in trouble call, and are assessed as part of NOCs.
- 6.4 On the basis that NIE Networks followed this definition, it appears that NIE Networks experienced three 1-in-20 atypical severe weather events in the first 4 years of RP5. However, the costs associated with 1-in-20 severe weather costs in 2014/15 are very small. The costs associated with atypical severe weather events are presented below:

Year	2015/16 prices
2012/13	£1,862,702
2013/14	£756,880
2014/15	£1,598
2015/16	£0

Table 22: atypical severe weather expenditure between 2012/13 and 2015/16

- 6.5 These events are in addition to the 1-in-20 atypical severe weather events identified as part of the RP5 price control review, in 2003/04 and 2007/08.⁶⁷ Therefore, since 2003/04, NIE Networks have experienced six 1-in-20 severe weather events, albeit the costs associated with the 2003/04 and 2014/15 are small in magnitude.

⁶⁷ In 2015/16 prices, the costs associated with 1-in-20 severe weather events were £210,000 in 2003/04 and £4,510,000 in 2007/08.

- 6.6 As suggested by CC at RP5 and NIE Networks, these figures do suggest that severe weather events according to Ofgem's definition do occur with greater frequency in Northern Ireland than 1 in 20 years.
- 6.7 The remainder of this section is organised as follows:
- i) Approach to severe weather costs taken in RP5.
 - ii) Outlines NIE Networks' atypical severe weather allowance proposal for RP6.
 - iii) Describes the Utility Regulator's proposal for an atypical severe weather allowance during RP6.

Approach to setting an atypical severe weather allowance at RP5

Context

- 6.8 AT RP5, our definition of a major storm event was a severe weather event that costs more than £1 million.
- 6.9 Both NIE Networks and ourselves had similar views on how costs associated with major storm events that pass this threshold should be treated:
- i) NIE Networks: Did not ask for an ex ante allowance for major storm events but proposed instead that storms that gave rise to costs above £1 million should be subject to a force majeure arrangement under which the Utility Regulator could make adjustments to NIE Networks' maximum regulated revenue during the price control period.
 - ii) Utility Regulator: Proposed an ex post adjustment to provide NIE Networks with additional revenue to cover the costs of atypical storm events.
- 6.10 Both approaches would result in costs associated with major storm events that pass the £1 million threshold being passed straight through to consumers. CC did not agree with this approach due to two main reasons:
- i) CC argued that wherever possible you should avoid cost pass-through which could expose consumers to unnecessarily high costs; and
 - ii) The definition of a major storm event could give rise to perverse incentives when considered alongside treatment of normal or typical expenditure. For example, if storms costing more than £1 million are passed through but storms costing less than £1 million are subject to an ex ante allowance, NIE Networks would face an incentive to increase the cost of storm events to the £1 million pass-through threshold.
- 6.11 Taking into account these reasons, the CC decided that it was not in the public interest to pass through costs associated with major storm events that pass the £1 million threshold. As a result, the CC decided it was appropriate to set an ex-ante allowance, while recognising the difficulties in setting the allowance.

CC RP5 Provisional Determination

- 6.12 CC's first step involved considering GB DNO data on gross costs associated with severe atypical weather over the period 2009/10 to 2011/12.
- 6.13 This data showed that no GB DNOs reported costs in this category in 2009/10 or 2010/11 and one GB DNO reported costs in this category in 2011/12 (£5.3 million).
- i) Over the three year period, the average cost per GB DNO was £126,000.
 - ii) For 2011/12, the average cost per GB DNO was £378,000.
- 6.14 Ofgem define atypical severe weather events as one-in-20-year events. CC used this definition by taking the atypical severe weather event cost reported in 2011/12 (£5.3 million), dividing by the number of companies whom incurred atypical severe weather costs in 2011/12 (1 company), and then dividing by 20 to reflect a 1-in-20-year event. This calculation resulted in annual allowance of around £265,000.
- 6.15 However, the CC noted that this figure would be higher or lower depending on the magnitude of the event being considered. For example, an event costing £1 million would imply an annual allowance of £50,000 (i.e. £1 million divided by 20).
- 6.16 As a result, the CC considered that a plausible annual allowance for severe storms was in the range of £50,000 (assuming a £1 million severe weather cost as previously defined) to £378,000 (average 2011/12 atypical severe weather cost per GB DNO).
- 6.17 Based on this analysis, the CC provisionally decided on an allowance of £200,000 a year, or £1,100,000, for RP5.

CC RP5 Final Determination

- 6.18 In response to CC's provisional determination, NIE Networks stated that severe weather events by the definition used by Ofgem had occurred with greater frequency in Northern Ireland than 1 in 20 years.
- 6.19 There had been three such events in the period 2003/04 to 2012/13 which cost £6.3 million in total.
- 6.20 NIE Networks argued that this implied an annual cost of £0.63 million and an RP5 allowance of £3.5 million.
- 6.21 The company also argued that the fact that NIE Networks had experienced three 'Severe Weather 1 in 20 events' in the period 2003/04 to 2012/13 meant that the CC should not base its allowance on the assumption that NIE Networks would experience only one atypical severe weather event in 20 years.
- 6.22 The CC considered that the frequency of NIE Network's experience of severe weather events since 2003/04 was relevant evidence to consider, and decided that NIE Network's experience in the last 10 years meant they should give a higher allowance than in CC's provisional determination.

- 6.23 However, the CC did not want to base an allowance on NIE Network's experience alone, and therefore decided to also take into account GB data.
- 6.24 As a result, the CC arrived at annual allowance for atypical severe weather of £0.36 million, or £2 million over the entire RP5 period.

NIE Networks' approach to setting an atypical severe weather allowance at RP6

- 6.25 NIE Networks are seeking an allowance of £4.6 million for RP6. This was calculated by considering the costs associated with 1-in-20-year severe weather events for the period April 2012 to December 2015 (3.75 years).
- 6.26 Total 1-in-20-year severe weather event costs for this period came to approximately £2.6 million which equates to approximately £0.7 million per annum (£2.6 million divided by 3.75). The total RP6 allowance was then calculated by multiplying £0.7 million by 6.5 to reach £4.6 million. This approach is similar to the approach taken by RP5 by NIE Networks in their response to CC's RP5 provisional determination.
- 6.27 However, for RP6 the company has decided to ignore costs associated with 1-in-20-year events incurred between 2003/04 to 2011/12, which were considered as part of RP5. In addition, NIE Networks have also decided to ignore 1-in-20-year event costs incurred by GB DNOs, which the CC considered to be an important part of the assessment of NIE Networks' 1-in-20-year atypical severe weather event costs at RP5.
- 6.28 Taking paragraph 6.27 into account, we consider that an alternative approach to setting an allowance for 1-in-20-year severe weather events during RP6 is more appropriate.

Utility Regulator's proposal for setting an atypical severe weather allowance during RP6

- 6.29 The Utility Regulator has decided to take a similar approach to the CC at RP5 in setting NIE Networks' atypical severe weather allowance for RP6.
- 6.30 We believe it is appropriate to analyse the longest time series available with regards to setting an atypical severe weather allowance as the first four years of RP5 may not be reflective of every four year period in recent history given the unpredictability and relatively low probability of atypical severe weather events.
- 6.31 A prime example of the unpredictability of atypical severe weather costs is the four year period 2008/09 to 2011/12. In this period NIE Networks did not incur any atypical severe weather costs. As a result, if we used this four year period and NIE Networks' approach to setting an atypical severe weather allowance we would not give NIE Networks an atypical severe weather allowance for RP6.
- 6.32 Furthermore, following CC's approach at RP5, we also consider it appropriate to take into account GB data as well as NIE Networks own data on atypical severe weather expenditure when setting an allowance for NIE Networks. This approach incentivises

NIE Networks' to be as efficient as possible when reacting to atypical severe weather events, and is therefore in the public's best interest.

- 6.33 We have access to atypical severe weather expenditure for NIE Networks between 2003/04 to 2015/16. In addition, we have access to atypical severe weather expenditure for GB DNOs between 2010/11 to 2015/16. As mentioned, we propose to use both of these time series to arrive at an atypical severe weather allowance for NIE Networks during RP6.
- 6.34 To arrive at an annual allowance we have taken the following steps:
- i) Convert all atypical severe weather expenditure for GB DNOs (2010/11 to 2015/16) and NIE Networks (2003/04 to 2015/16) to a common price base (2015/16 prices). We use Chaw RPI all items index.
 - (i) GB DNO expenditure data are taken from Ofgem RIIO-ED1 RIGs.
 - (ii) NIE Networks expenditure data is taken from the company's C1 matrices, included as part of their RP6 business plan submission, and through CC's RP5 final determination.
 - ii) Calculate the average GB DNO atypical severe weather expenditure over the period 2010/11 to 2015/16 (6 years of data):
 - (i) Sum up expenditure across DNOs (14 DNOs) and time (6 years). In total there are 84 observations (14 DNOs x 6 years).
 - (ii) Divide by the number of years in the sample (6 years).
 - (iii) Divide by the number of DNOs (14 DNOs).
- 6.35 Calculate the average NIE Networks atypical severe weather expenditure over the period 2003/04 to 2015/16 (13 years of data):
- (i) Sum up expenditure over time (13 years).
 - (ii) Divide by the number of years in the sample (13 years).
- 6.36 Weight together the average GB DNO atypical severe weather expenditure and the average NIE Networks atypical severe weather expenditure by summing together:
- i) "GB DNO average atypical severe weather expenditure over the period 2010/11 to 2015/16" multiplied by the number of GB DNOs divided by the number of UK DNOs" (i.e. 14/15); and
 - ii) "NIE Networks average atypical severe weather expenditure over the period 2003/04 to 2015/16" multiplied by one divided by the number of UK DNOs (i.e. 1/15).
- 6.37 By taking this approach we arrive at an annual atypical severe weather allowance of approximately £324,389 (2015/16 prices):

- i) GB DNO average expenditure over the period 2010/11 to 2015/16 is £307,315;
- ii) NIE Networks' average expenditure over the period 2003/04 to 2015/16 is £563,419;
- iii) Weighted average = $[\text{£}307,315 * (14/15)] + [\text{£}563,419 * (1/15)] \approx \text{£}324,389$

6.38 Therefore, the total proposed NIE Networks atypical severe weather allowance for the entire RP6 regulatory period is approximately £2.11 million (£324,389 multiplied by 6.5 years).

Rates

Overview of Business Rates

- 6.39 This section deals with our proposed approach to Business Rates (referred to as 'Rates' henceforth). Rates are effectively a tax on the occupation of property.
- 6.40 The Rates liability is determined by reference to (a) the net annual valuation (NAV); and (b) the district and regional Rates (poundage Rates) which are applied to the NAV by the ratings office. The regional Rate is set annually by the Northern Ireland Executive and is applied to each district council area in Northern Ireland. The district rate is set annually by each district council in Northern Ireland.

NIE Networks RP6 Business Plan Submission

- 6.41 NIE Networks is seeking circa £118m for Rates in its RP6 BP submission. The Business Plan requested Rates profile is as shown in the table below and the split between the Transmission and Distribution businesses is based on the respective business RABs.

	6 mths to Mar 2018 (£m)	2018-19 (£m)	2019-20 (£m)	2020-21 (£m)	2021-22 (£m)	2022-23 (£m)	2023-24 (£m)	RP6 Total (£m)
Distribution	6.9	13.9	13.9	14.0	13.9	14.0	14.0	90.5
Transmission	2.1	4.2	4.2	4.2	4.3	4.2	4.2	27.5
Total	9.0	18.1	18.1	18.2	18.1	18.2	18.2	118.0

Table 23: NIE Networks' RP6 Business Plan submission for Business Rates

Rates in Previous Price Controls

- 6.42 The approach to Rates has differed across previous price controls, with different approaches adopted by different regulators. There is no established regulatory precedent in this area and each company and price control should be evaluated based on its specific circumstances.

RP4

- 6.43 In RP4 the Utility Regulator specified that Business Rates should be treated as pass through costs as at that time they were considered uncontrollable opex and should be passed through in full to consumers.

CC Final Determination for RP5

- 6.44 The CC examined the treatment of Rates in its RP5 Final Determination (https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf). It set upfront allowances for RP5 in line with the table below. In addition, the CC stated that Rates were one of the cost items which could be subject to a 50/50 sharing mechanism between consumers and the company – whereby if costs deviated from set allowances the deviation – either positive or negative could be shared between company and consumer.
- 6.45 The CC argued that setting the treatment of Rates as ‘uncontrollable’ and recoverable on a full cost pass through basis may expose consumers to excessively high charges that reflect unnecessary expenditure or missed opportunities for cost reductions. It considered that NIE Networks may have some influence over these costs.

	2012-13	2013-14	2014-15	2015-16	2016-17	6 mths to Sept 2017	RP5 Total
£million (2009-10 prices)	12.6	12.7	12.7	12.8	12.9	6.45	70.15

Table 24: CC RP5 Allowances for Rates (2009-10 prices)

RP5 Rates Performance

- 6.46 NIE Networks has already made several representations to the Utility Regulator to state that its Rates liabilities have increased following the 2015 Rates revaluation from £15m to £18m per annum leaving them with a ‘shortfall’ for the last 2.5 years of RP5 in the region of £3m per annum.
- 6.47 NIE Networks was last revalued for Rates purposes on 1 April 2015 as part of a wider revaluation of all Northern Ireland non-domestic properties. At this 2015 valuation LPS changed its approach from one specified by the Department of Finance to a conventional assessment based on income and expenditure levels.
- 6.48 However, we note that as Rates is one of the cost items which is subject to the 50/50 sharing mechanism meaning the ‘shortfall’ is actually not £3m per annum, rather it is £1.5m per annum.

RP6 Draft Determination Proposal for Rates

NIE Networks arguments for Rates to be treated as pass through

- 6.49 NIE Networks are of the opinion that Rates should be treated as pass through for RP6. NIE Networks state that they have no control over the approach adopted by LPS in setting the NAV and the poundage Rates which are applied to the valuation.
- 6.50 They have cited two additional areas of uncertainty in RP6 – the potential construction of the North –South Interconnector and an associated Rates increase and uncertainties associated with a possible 2020 Rates revaluation.
- 6.51 It is common for regulated companies actual expenditure to deviate from allowances set by Regulators and deviations can be both positive and negative and may result in cost savings and cost increases. The company is in part shielded from these effects by various regulatory mechanisms including the 50/50 cost-sharing mechanism and also via the setting of the Rate of Return.

NIE Networks submission on the North– South Interconnector

- 6.52 NIE Networks consider that the North- South Interconnector would add in the region of £4.5m to the Current NAV and that this would have a consequent increase in Rates of £2.5m per annum.
- 6.53 It is important to note that this allowance was not included within NIE Networks Business Plan submission; but rather this request has been made separately since the Business Plan submission.

Utility Regulator proposed approach

- 6.54 We have considered NIE Networks' submission and the information provided via Business Plan queries and additional submissions.
- 6.55 We are not proposing to allow Rates as a pass through item. We note that we do not allow Rates as a pass through item in our GDN or NI Water price controls. We consider it appropriate to follow the precedent set by the CC in the RP5 Final Determination and set allowances for RP6 with the option to apply the 50/50 sharing mechanism between the company and consumers for any over/ under recoveries.
- 6.56 We consider that Rates are not wholly uncontrollable and there is an element of negotiation between NIE Networks and LPS.
- 6.57 In terms of the figure to use for Rates we have not completed out analysis and will require further information before finalising a figure. However for this Draft Determination we have provisionally included the amounts submitted in NIE Networks' Business Plan submission for Business Rates. However, we intend conducting a comprehensive review between the Draft and Final Determinations to formulate a final view on appropriate levels of Rates for RP6. We will also consider the most up to date information available in formulating our final approach.
- 6.58 It should be noted that it is highly likely that the allowances set in the DD will change for the FD.

- 6.59 We have considered the impact of the North- South Interconnector construction on Rates. NIE Networks has stated that they estimate the impact to be of the order of £2.5m per annum. However, there are uncertainties including: the timing of completion and also the timing and magnitude of any Rates impact as a consequence.
- 6.60 We consider it appropriate to not include allowances for Rates in relation to the North South Interconnector until such time as it is operational, assessed for Rating purposes and actually being billed on the NIE Networks Rates bill. We will consider further how this might be dealt with under the D5 mechanism as set out in section 13.
- 6.61 We are also uncertain as to whether the 2020 Rates revaluation will occur and also the potential impact of this on NIE Networks' Rates bill- it may have no significant impact or alternatively it could result in a reduction or conversely an increase on the level of Rates to be paid. Therefore without firm evidence we do not plan to take any account of changes to Rates in 2020.
- 6.62 For the purposes of this Draft Determination we have included the provisional allowances for Business Rates as shown below. However, we will continue to assess Rates more fully before coming to a view for our Final Determination for RP6. In the absence of any contradictory evidence, we propose using the Transmission and Distribution business splits as for Rates presented by NIE Networks - based on the respective Business RABs.

	6 mths to Mar 18	2018-19 (£m)	2019-20 (£m)	2020-21 (£m)	2021-22 (£m)	2022-23 (£m)	2023-24 (£m)	RP6 Total (£m)
Distribution	6.9	13.9	13.9	14.0	13.9	14.0	14.0	90.5
Transmission	2.1	4.2	4.2	4.2	4.3	4.2	4.2	27.5
Total	9.0	18.1	18.1	18.2	18.1	18.2	18.2	118.0

Table 25: RP6 Draft Determination *provisional* allowances for Business Rates (2015-16 prices)

7 Information and Communication Technology (ICT)

Introduction

7

- 7.1 Gemserv was appointed to provide a bottom-up assessment of the non-network oriented Information and Communications Technology (ICT) proposals contained within the RP6 Business Plan.
- 7.2 Gemserv was appointed in September 2016 to provide support to the Utility Regulator in assessing costs associated with IT, Market Operations & Enduring Solution. Gemserv prepared an initial review of the Market Operations Non Network IT aspects of Northern Ireland Electricity Networks (NIE Networks) RP6 submissions in December 2016.
- 7.3 Following on from the report, Gemserv was instructed to widen its scope to consider the Non Network IT aspects of NIE Networks' proposals. Both reports from Gemserv accompany this draft determination at:
- Annex D – GEMSERV Market Ops Non-Network IT Assessment
 - Annex E – GEMSERV Non Network IT Assessment
- 7.4 Unless stated otherwise for this chapter, all quoted capex and opex numbers are in 2015/16 prices.

Scoping

- 7.5 The following areas were identified as being in scope:

Assessing the following aspects of the Non-Network IT Business Plan:

- All forty-eight (48) project proposals plus the Small Project proposed spend and assessing them across the three categories of project: Infrastructure; Telecoms; and Applications.
- Assessing the proposed capex and opex for those projects to determine whether they are fair and reasonable.
- Ensuring that the capex and opex apportionment to Market Operations is fair and correct.
- Analysing the level of optionality associated with those projects giving the Utility Regulator the ability to identify potential cost savings.
- Assessing NIE Networks' proposed "efficiency projects".

- Assessing NIE Networks' programme management and backfill costs.
- Review of project refresh timelines.
- Considering NIE Networks' proposed IT Strategy to assess whether it is appropriate within the context of RP6, determining whether the proposed projects align with that strategy, and factoring in whether that investment is necessary.

Revisit the analysis of the Market Operations allocation, the Enduring Solution planned spend, proposed Tibco capex and opex, and Market Operations – Other Operating Costs from the first report in light of:

- The wider analysis of the Non Network IT spend above,
- Feedback from NIE Networks in relation to the outstanding queries raised and further submissions that they may provide.

Revisit the analysis of the Managed Service Provider Agreement from the first report and review in the context of all Non Network IT expenditure

7.6 As this contract is under procurement the final costs will not be available until spring 2017.

Out of scope

7.7 The following areas were identified as being outside the scope of the Gemserv assignment:

- Costs in relation to contestability of connections;
- IT costs in relation to D602 ("Investing for the Future") of the Networks Investment Plan;
- Capex costs in relation to Metering under the Market Operations Business Plan;
- Ensuring the proposed allocation of costs within the Connections category of the Non-Network IT Business Plan are accurate and reasonable;
- Reconciliation of Market Operations Non Network IT figures and Connection allocation across the Business Plan and the Networks Investment Plan to ensure consistency across the submissions and accuracy of the proposed allocations;
- Building a financial model to inform the analysis of Market Operations costs and Connections Allocation;
- Analysis of non-capex costs related to meter installations changes and meter recertification; and
- Assessment of costs in relation to meter reading during the price control.

Approach to RP6

- 7.8 A consideration for Gemserv in developing its analysis of NIE Networks' submission was our RP6 Approach document. Some key principles from that document that informed Gemserv's approach included *inter alia*:
- Providing an efficient revenue cap to enable NIE Networks to deliver the required outputs
 - Justification of additional opex on the basis of two tests:
 - a. Newness – expenditure is related to a new obligation or specified service level improvement; or
 - b. Exogeneity – is there an exogenous factor driving cost increases in relation to current business activities.
 - Delivery of the price control should maximise the ability of NIE Networks to determine the optimum way to deliver the level of service required by consumers at an efficient cost; and
 - Where proposing service improvements, NIE Networks should be able to quantify those improvements in terms of tangible outcomes and which consumers can understand and have supported.
- 7.9 Gemserv were asked to adopt a “bottom up” analysis in relation to the IT costs, looking at the proposed instances of project spend and building that up into a set of recommendations. Where NIE Networks is able to demonstrate that projects will deliver customer benefits in line with these principles this will be taken into account in the final determination.

Efficiency projects

- 7.10 The Utility Regulator has maintained the principle that if a productivity gain from an initiative or suite of initiatives is such as to outweigh the actual costs of implementing it, then it would seem to be economically justified on its own merits. It would also suggest that such projects are self-funding and should not be included in price controls. On that premise, it would also seem that seeking to recover the costs of the project from customers is unnecessary and would suggest that the associated capex and opex are not justified for inclusion in the price control.
- 7.11 On the basis of their detailed analysis and company submissions to date, the Utility Regulator was not convinced of the merit of an allocation within the RP6 for efficiency projects and instructed Gemserv accordingly.

Optionality assessment

- 7.12 Gemserv performed an analysis of the degree of optionality associated with IT projects i.e. whether they were actually required during the RP6 price control period.
- 7.13 Gemserv's analysis has been grounded in an assessment of the operational practices of NIE Networks from written submissions and engagement at workshops.

The company has repeatedly portrayed their current operational practices as heavily paper based and potentially risky or unsuitable for a distribution company during the period of 2017-2024.

Managed service provider agreement

- 7.14 NIE Networks contract with a third party for much of their ICT services under a managed service provider agreement. This agreement is a significant input into ICT costs, and is currently under procurement for the period of 2017-2024. Before the final determination this area of ICT expenditure shall be re-appraised given the likely progress to final award by end June 2017.

Gemserv reports

- 7.15 Further details regarding Gemserv's approach, findings and recommendations are contained within their two reports (i) Non Network IT Assessment Report and (ii) Market Operations – Non Network IT Assessment Report which we include as Technical Annexes.

Non Network IT Capex Recommendations

- 7.16 The capex impacts of the above on the total proposed Non Network IT capex are:
- Exclusion of £896.2k in relation to the Managed Service Provider Agreement;
 - £2.13m capex that should not be included in relation on the basis of an efficiency rationale;
 - Reallocation of £690k Ongoing Enhancement capex to opex;
 - Non-inclusion of £275k of Small Projects capex, and reallocation of the remaining £1.95m Small Projects capex to opex;
 - £2.45m of capex related to Programme Management and Backfill that should not be permitted;
 - £1m of capex in relation to late SAP HANA projects that should not be included under RP6; and
 - £1.9m of capex that should be excluded as a result of the optionality analysis.
- 7.17 In total, these recommendations result in £9.95m being disallowed.

Non Network IT Opex Recommendations

7.18 Outlined below are the Project Specific opex recommendations:

- £661.8k of Market Operations related opex should not be included within RP6;
- £179.9k should be excluded as a result of likely efficiency gains in relation to the Managed Service Provider;
- £215k should not be permitted as a result of projects being excluded on the basis of the efficiency analysis referenced above;
- £843k should not be permitted on the basis of project spend not being permitted as per the optionality analysis discussed above;
- The reallocation of £630k expenditure related to Ongoing Enhancements from capex to opex; and
- The reallocation of £1.95m Small Project expenditure to opex.

7.19 The following recommendation relates to the Non Project Specific opex:

- Exclusion of the £40k Qlik expenditure from the proposed Non Network IT opex.

7.20 The net effect of the recommended exclusions and reallocations is a net increase in the overall opex budget of £837.4k.

Enduring Solution Opex

7.21 The following recommendation relates to the Enduring Solution opex:

- £1.72m should not be permitted under the IT Support Costs category
- £59.9k of the proposed Market Entry Costs should not be included within RP6.
- £1.67m of cost should not be permitted under the Market Services Staff category.

Consolidated Impact of Recommendations

- 7.22 Set out below is the consolidated impact of the above recommendations on the proposed Non Network ICT expenditure.
- 7.23 Where relevant various adjustments for connections costs/income have been included to derive the net totals for subsequent input to the RP6 Financial Model.

Category	NIE Networks Proposed	Net Recommendation	Outturn	Connections allocation	Net Total
Non Network IT Capex	£ 41,882,046	-£ 9,949,553	£ 31,932,493	-£ 4,294,973	£ 27,637,520
Non Network IT Opex	£ 8,887,000	£ 837,440	£ 9,724,440	-£ 3,658,292	£ 6,066,148
Enduring Solution Opex	£ 34,133,500	-£ 3,453,179	£ 30,680,321	£ -	£ 30,680,321
Market Operations - Other Opex	£ 27,936,665	£ -	£ 27,936,665	£ -	£ 27,936,665
Subtotal	£112,839,211	-£ 12,565,291	£100,273,919	-£ 7,953,265	£ 92,320,655

Table 26: Consolidated impact of Non Network IT recommendations

Next Steps

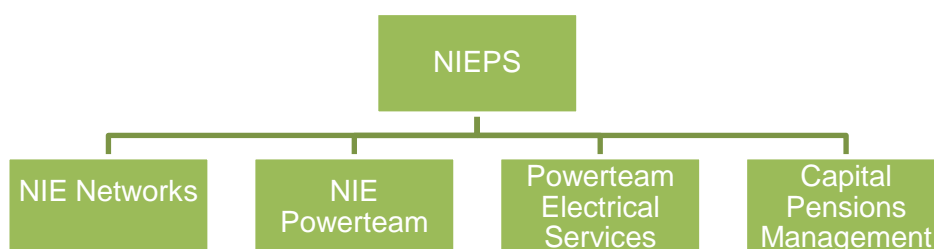
- 7.24 Whilst the Utility Regulator has accepted Gemserv recommendations at this draft determination, our primary focus across the RP6 period shall be NIE Networks' total spend on ICT.
- 7.25 Since NIE Networks will have flexibility to move money around within its ICT activities during RP6, the Utility Regulator will expect ICT projects and activities to be monitored and reported against so we can understand how costs evolve against RP6 allowances. We would also expect that NIE Networks may decide to invest in ICT projects which are funded through the efficiencies they deliver elsewhere in the company.
- 7.26 As part of our draft determination consultation we expect to discuss the means by which we shall monitor and report ICT against the RP6 price control.
- 7.27 Further ahead as we develop the over-arching RP6 Monitoring Plan (to be detailed on the basis of company acceptance of the final determination) we shall ensure all funded ICT investment is reported on an annual basis. This will ensure all the ICT deliverables are tracked across the RP6 period and any under/over-performance reviewed, especially as we:
- approach NIE Networks' next price control at RP7; and
 - prepare our annual Cost and Performance Report of NIE Networks' progress against RP6 outputs and deliverables.

8 Pension Deficit Repair

Overview of NIEPS

8

- 8.1 This section deals with our proposed approach to pension deficit recovery allowances for RP6. This chapter provides an overview of our decisions and proposed allowances for RP6 in relation to pension deficit aspects. Our Pensions Annex F provides additional detail on our review of pension aspects. In addition, ongoing pension contributions and benchmarking are discussed in section 5 of the DD.
- 8.2 The NIEPS is a multi-employer scheme. This means that other companies (both regulated and non-regulated) are also members of the scheme. Current employers that participate in the NIEPS are: Northern Ireland Electricity Networks Ltd (referred to as NIE Networks throughout this paper), NIE Powerteam Ltd, Powerteam Electrical Services Ltd, and Capital Pensions Management Ltd.



- 8.3 The pension scheme operates two sections as follows:
- Defined Benefit (DB) section, referred to as the 'Focus' plan; and
 - Defined Contribution (DC) section, referred to as the 'Options' plan.
- 8.4 In March 1998, NIE (now NIE Networks) closed the DB section of the pension scheme to new entrants. Since then, new joiners are instead offered membership in the DC section of the scheme.⁶⁸ This is consistent with general trends in UK private sector pensions.
- 8.5 In the DB section of the scheme an employee's pension is based on the number of years of service and final salary with sponsoring employer(s). The level of future pension benefit and employee will receive is set; the investment risk lies with the employer(s).
- 8.6 The Electricity (Protected Persons) Pensions Regulations (Northern Ireland) 1992 protect certain employees' pension benefits in respect of past and future service.

⁶⁸ See [Northern Ireland Electricity Limited: Transmission and Distribution RP5 Price Control, Statement of Case to the Competition Commission, 10 May 2013](#).

This protection restricts the extent to which the NIEPS's benefits and member contribution rates can be changed.

- 8.7 In the DC section of the scheme an employee's benefits will be dependent on the contributions to, and growth of, the fund and the fund manager's investment and other attributable costs. There is no guarantee on the level of future pension benefit an employee will receive; the investment risk lies with the employee.
- 8.8 The main difference between DB and DC provision relates to risk: in a DB scheme the employer bears the risk of adverse future experience through the possibility of deficiency contributions being required, whereas in a DC arrangement the risk of adverse future experience rests with the member through lower than expected benefits. Conversely, members benefit from favourable experience in a DC arrangement, whereas in a DB scheme the employer may benefit (depending on the scheme rules).
- 8.9 The table below provides an overview of the number of active members (members who are currently working) in both the DB and DC sections of the NIE Networks' pension scheme at 31 March 2014.

Scheme Section	Defined Benefit membership (Focus)	Defined Contribution membership (Options)
Actives	586	687
Deferred pensioners	752	752
Pensioners and dependents	4,391	56
Total	5,729	1,495

Table 27: NIE Networks' pension scheme membership breakdown as at 31 March 2014

- 8.10 NIE Networks' pension scheme is managed by a Board of Trustees who act separately from the employer and hold assets in the trust for the beneficiaries of the scheme. Trustees are responsible for ensuring that the pension scheme is run properly and that members' benefits are secure. The Trustees negotiate pension aspects for the benefit of members with NIE Networks – for example deficit payments, contributions, etc and the company makes appropriate payments. Trustees are ultimately responsible for the operation of the pension scheme. Trustees take into account the financial position and the strength of their covenants when forming a view of a deficit recovery plan for the scheme.

- 8.11 Advisers, including actuaries, lawyers, and investment consultants are engaged by the Trustees to advise them on the financing and funding of the pension scheme by considering the relative risks of investment and funding approaches.
- 8.12 The NIEPS is subject to various statutory obligations and will need to provide information to the Pensions Regulator (TPR) to ensure and demonstrate compliance. TPR is the UK regulator of work- based pension schemes and its objectives are set out in legislation (for additional information refer to: <http://www.thepensionsregulator.gov.uk/about-us/our-objectives.aspx>)
- 8.13 NIE Networks makes contributions to its pension fund on behalf of current employees who are members of the pension scheme. Since privatisation, the pension scheme has moved from a surplus to a deficit position (where the assets of the scheme are less than the liabilities).
- 8.14 NIE Networks' pension deficit arises from the defined benefit section of the pension scheme. A deficit is the amount by which the present value of the pension fund liabilities exceeds the value of the assets. Deficit repair payments are cash amounts, agreed with the pension scheme trustees, which the company pays to reduce a pension fund deficit.
- 8.15 NIE Networks makes several types of payment to the scheme including principally:
- Ongoing pension payments to represent the cost of additional benefits being accrued by existing employees who are still members of the scheme (which are both DC and DB costs);
 - Annual deficit repair payments which aim to bring the scheme into balance over a period of time (which are DB associated costs); and
 - The Cost of insured risk benefits (which are DC related costs).
- 8.16 We commissioned the Government Actuary's Department (GAD) to provide expert advice on pension aspects including investment strategy, actuarial assumptions and pension scheme valuation and funding. This Draft Determination section is complemented by a Technical Annex produced by GAD (Annex G) which deals with more detailed pension aspects and may be read in conjunction with this document.

NIE Networks RP6 Business Plan Submission

- 8.17 NIE Networks populated the business plan templates submitted by us, which follows the OFGEM approach on data capture.
- 8.18 NIE Networks proposed an allowance of £84m (in 2015-16 prices) for pension deficit recovery costs during the RP6 period. This sum is to cover the cost of repairing a deficit in the defined benefit scheme to ensure that accumulated liabilities for both current and past employees are met.

	RP6 Request £m (6.5 years) in 15-16 prices
Pension Deficit Contribution	114.5
Pension ERDC disallowance	(30.5)
Net Amount Requested (£m)	84.0
Average annualised amount (£m)	12.9

Table 28: NIE Networks RP6 Business plan Submission 2017-2024

- 8.19 The RP6 request is based on the Triennial Actuarial Valuation of the 31 March 2014. This Actuarial Valuation usually takes 12 months to conclude, before a full assessment of the scheme funding is known. The results of this valuation led NIE Networks to reforecast its pension scheme funding requirements on the 27 May 2015- when it produced an updated '**Schedule of Contributions**' which covers contributions to the pension scheme for the period 1 April 2014 – 31 March 2022.
- 8.20 However, NIE Networks has requested additional funding in its Business Plan up until the end of RP6 in 2024, which is different to the target date set of 2022, as set by the CC on RP5. This represents additional requested funding for the period 2022-2024. This request has been made as NIE Networks consider deficit recovery payments are required for additional years beyond the 2022 as stated by the CC.
- 8.21 In making our assessment of RP6 allowances we will consider NIE Networks; submission, CMA (and CC) determinations, regulatory precedents and other relevant material.

RP5 Decision- The CC Determination and Principles

- 8.22 On 30 April 2013 the RP5 price control determination was referred to the CC (now the CMA). In its final determination, the CC ruled that the treatment of pension deficits as part of the RP5 price control should be consistent with Ofgem's treatment of pension deficits of distribution businesses in GB⁶⁹.
- 8.23 In the RP5 CC FD the following key decisions were made in the DB area:
- With regard to the **scheme deficit**, in which the current scheme has insufficient assets to cover its liabilities it was split into 2 areas, between an **established deficit** (represents the difference between assets and liabilities attributable to pensionable service up to 31 March 2012 and 100% funded by consumers) and **incremental deficit** (represents the difference between assets and liabilities for

⁶⁹ See [Competition Commission: Northern Ireland Electricity Limited price determination, Final determination, 26 March 2014](#), paragraph 12.80.

pensionable service from the 1 April 2012 and 100% funded by shareholders;). This is similar to the approach used by OFGEM;

- The Deficit repair allowances, to recover the costs in relation to the established deficit, was set to the 31 March 2022, which was a 10 year period from the commencement of RP5. This also matched the payment profile between the company and the trustees;
- The Early Retirement deficit contribution liability (ERDCs), which was an enhancement to pension benefits with no additional funding, due to the scheme being in surplus, that occurred between 1997-2003. Based on the evidence and payment profile it was decided that 30% of the historic deficit repair allowance, would be disallowed and be funded by shareholders.
- In period adjustment Mechanism which makes changes to the payment schedules, normally after an actuarial valuation, to reflect the scheme needs, is deferred to the start of the next price control on the basis that NIE and consumers are kept NPV neutral due to timing;
- With regard to the Deficit repair payment from RP4 in excess of RP4 allowance - not to provide any allowance for costs incurred in RP4 in excess of those allowances provided in RP4.

8.24 The CC in its determination ruled that the established deficit repair allowance for RP5 should match the deficit repayment profile that NIE Networks has agreed with the trustees of the pension scheme (that is £13.7m per annum during RP5 in 09-10 prices with a reduction for ERDC (refer to Annex F on Pensions for additional detail)). The established deficit repair allowances were set for ten years from the start of RP5 to 31 March 2022- this was similar to the approach used by Ofgem. The CC allowances for RP5 were as follows:

	RP5 FD (2009-10 prices) (5.5 years) £m (Per CC)
Pension Deficit Contribution	75
Pension ERDC disallowance	(22)
Net Amount Requested (£m)	54
Average annualised amount (£m)	9.8

Table 29: CC RP5 FD allowances for NIE Networks Pension Deficit Recovery Payments

8.25 We stated in our final approach for the RP6 price control, published in December 2015, the following: '[... we] consider that the pension principles we apply in setting pension-related price control allowances should be consistent across all NI regulated energy businesses with defined benefit schemes as well as, in so far as reasonable and practical, also with the pension principles used by Ofgem. [...] For RP6, we therefore propose to build on the pension principles used as part of RP5. We may consider reviewing our pension principles in the future as part of a roll-out and

alignment of pension principles across all NI regulated energy businesses with defined benefit schemes⁷⁰.

Historic Deficit Repair Responsibility

- 8.26 The CC made a decision in RP5 that the historic deficit, pre April 2012 should be 100% funded by consumers. The following extract outlines the CC's approach:

"Based on our view that NIE is likely to have a limited ability to mitigate the historic scheme deficit, we decided that in principle (and before considering any special items) 100 per cent of historic deficit repair costs should be passed through to consumers during RP5."

- 8.27 This principle is similar to the one Ofgem has in place for GB DNOs. We note that the reasons CC gave for this decision have not changed and we do not propose to change this principle in RP6.
- 8.28 In addition, the CC set a regulatory fraction of 99.26% - this was deemed to be the proportion allocated to the regulatory business and the CC adjusted deficit allowances accordingly.
- 8.29 Following on from the CC recommendations and as part of its Business Plan submission for RP6, NIE Networks were required to complete a Pension Deficit Allocation Methodology spreadsheet (PDAM) and accompanying commentary document (which may be found at: <https://www.uregni.gov.uk/publications/rp6-documentation-group-1>). The PDAM is based on the Ofgem methodology and shows the methods used by the company to allocate the pre and post cut-off assets and liabilities. This allows collection of data between the pre cut-off fund – before 31 March 2012 (consumers' responsibility) and the post cut-off fund (post 31 March 2012 (shareholder responsibility)).

Historic Deficit Repair Allowance

- 8.30 The CC set a deficit repair allowance to remove the deficit over 10 years. NIE indicated in its comments to the CC that having a notional "Stop dead date" was not appropriate as circumstances outside their control may increase the deficit.
- 8.31 The CC said (12.36) *"In our view, this would be a matter for UR to decide at subsequent regulatory determinations"*. The CC in a footnote indicated the following *"the deficit repair period might be extended by the UR in order to protect different generations of consumers"*.
- 8.32 In NIE Network's Business Plan submission they have continued to profile deficit recovery contributions for the two final years of RP6 to 2024, beyond the RP5 CC decision of ending by 2022. In its response to a UR query NIE Networks stated that it considered that current contributions would be insufficient to reduce the deficit at September 2016 of £262.8m by 2022 and that it considered that the recovery plan would continue beyond 2022, but at higher levels.

⁷⁰ [Utility Regulator: Northern Ireland Electricity Networks Ltd Transmission & Distribution 6th Price Control \(RP6\), Final Overall Approach, December 2015](#), paragraphs 128 and 129.

- 8.33 The UR is minded to allow extra contributions, recognising the worsening of the funding position. However, it is not certain that deficit contributions will be required beyond 31 March 2022 and we highlight that the allowances for 2022-2024 are **not** additional allowances and the UR will adjust for any excess amounts at the next Price Control, if appropriate. We will assess whether the decisions and actions taken in relation to pension scheme funding and investment were reasonable, justified and necessary in determining the level of adjustment.
- 8.34 We also note that should the pension scheme be in surplus at the time of the RP7 review we will make a negative adjustment to the allowances granted for 2022-24.

Approach taken by other Regulators in relation to pension deficit recovery

- 8.35 Ofgem has consulted on its approach to pensions twice in recent years (May 2015 and March 2016); however at the time of writing the decision paper for the latest consultation has not been published. Ofgem had previously envisaged pension scheme deficits being repaid over a fixed 15-year period. However, having identified some potential issues with the use of a fixed 15-year period, Ofgem's expected future direction will include more flexibility by not specifying what the *recovery period* should be, provided it is funded over a reasonable period and encouraging trustees to run pension schemes in an efficient manner.
- 8.36 In contrast to the Ofgem approach, Ofwat disallowed 50% of deficit contributions as it believed this would create a stronger alignment between the shareholders and consumer interests. Ofwat has also stated that it will allow no more deficit contribution payments beyond the end of the recovery plans agreed in 2009. The end dates for these recovery plans typically range from 2019 to 2025.
- 8.37 A different approach was adopted by Ofcom which disallowed all deficit contributions in determining pension cost allowances for BT.
- 8.38 We observe that there are a variety of potential approaches in relation to deficit recovery allowances as demonstrated by the range of approaches adopted by Regulators. Each scheme must be considered based on its individual characteristics considering scheme funding, level of deficit, strength of Employers' Covenant, scheme management, level of controllable and uncontrollable variables and other relevant aspects.

RP5 adjustments

- 8.39 Before we set RP6 allowances we must consider whether any adjustment is required in respect of previous price controls – RP5 in particular. Our review indicates that contributions during RP5 (and RP4) have been payable as expected in the CC FD and in line with the set schedule of contributions and therefore we do not believe that any adjustments are required in respect of contributions for service accrual or deficit recovery, which account for the majority of NIE Networks RP5 contributions. Therefore, we do not propose making any adjustment in respect of RP5 (or RP4).

Introduction

8.40 In determining price control allowances we have considered:

- the appropriate deficit amount to be considered,
- a deficit recovery period,
- the regulatory fraction which can be applied to NIE Networks to ensure that consumers only fund the element of pension costs which apply to the regulated entity;
- any disallowance to be attributed to the employers' contribution for deficit recovery in respect of the ERDC;
- the split of pension deficit recoveries between the Transmission and Distribution businesses;
- the strength of the employer's covenant.

8.41 NIE Networks completed pension returns for the Business Plan including the Pension Deficit Allocation Methodology (PDAM) submission. The PDAM captures the scheme position up to the 31 March 2012 and from the 1 April 2012 onwards and it is modelled on the Ofgem approach, following the recommendations made in the CC FD for RP5.

8.42 We have mainly used the pension scheme valuation as at the 31 March 2014 as it provides the latest formal valuation before the start of the RP6 period and also considered funding updates. The 2014 valuation is the valuation used by the Trustees in setting the Schedule of Contributions. The 31 March 2014 formal actuarial valuation reported a deficit of £110.7m. We have used this valuation and also the latest funding information to inform our decision. We note that we will review subsequent changes in funding position, investment strategies and other relevant pension aspects at RP7, including determining the appropriate level of adjustment in respect of allowances for the 2022-24 period. We note that should the pension scheme be in surplus at RP7 we will make a negative adjustment to the deficit allowances for the 2022-24 period.

8.43 The strength of the employer's covenant is imperative in making an assessment of any pension scheme, its financeability and investment strategy and we outline our considerations below.

Employer Covenant

- 8.44 An *Employer Covenant* relates to the extent of the legal obligation and financial ability of the employer to support the funding requirements and investment risks associated with its pension scheme. (Additional details on the Employer Covenant are included within the Pensions Annex F including a definition of same). A major consideration affecting the trustees' choice of valuation assumptions, and in particular the degree of *prudence* incorporated, is the trustees' view of the *employer's covenant*. The greater the trustees' perceived risk of the sponsoring employer's insolvency, the more *prudence* they are likely to apply.
- 8.45 We have requested the Employer Covenant from NIE Networks; however, this request was not forthcoming as the Trustees would not provide this to the Regulator. We are concerned that we have not been in receipt of this Covenant and would hope that we will receive it in the future to facilitate a holistic review of the NIEPS. NIEN has stated that the NIEPS's trustees' view of its covenant is 'tending to strong'. Therefore, we have accepted this view in the absence of any verifiable material.

Regulatory Fraction

- 8.46 The regulatory fraction was set as 99.26% at RP5 by the CC based on pro-rating scheme liabilities according to members' regulated service periods. However, the CC also considered two alternative methods which would have produced significantly different fractions and any of these methods might arguably have been viewed as reasonable.
- 8.47 In the RP6 Business Plan NIE Networks have included an adjustment to the Regulatory Fraction (leading to a factor in excess of 100%) which has been used as a tool to reallocate a certain amount of surplus (e.g. in respect of the article 75 ⁷¹debt payment). We have concerns that a Regulatory Fraction of over 100% may not be appropriate in other contexts (for example if it was being used as a post cut-off date Regulatory Fraction).
- 8.48 In view of the above and the fact that there are various possible methods for calculating the Regulatory Fraction we propose setting the Regulatory Fraction to 100% for RP6 and going forward. This will be a one-off adjustment and will effectively remove the requirement to adjust for the proportion allocated to regulatory activities and will simplify calculations going forward. This will result in an increased pension deficit repair allowance in the range of £0.8m as compared to NIE Networks' Business Plan submission. We do not propose to make a retrospective adjustment in respect of RP5 and previous price controls since this would involve adjustment for other price control aspects as it could not be adjusted in isolation. (For additional detail on our evaluation of the Regulatory Fraction, refer to the Pension Annex F.) We welcome views from consultation respondents on our proposed treatment of the

⁷¹ NIE Networks have included a 3.7% adjustment in respect of an *article 75 (of the Pensions Act) payment* (as Powerteam Electrical Services (UK) Ltd (PES) ceased to participate in the scheme on the 24th December 2013). The total scheme deficit has been split according to regulated or non-regulated status. NIE Networks have adjusted the *Regulatory Fraction* so that the surplus emerging in respect of the PES *article 75 payment* is treated as non-regulated surplus (and so increases the RP6 allowances).

Regulatory Fraction and will review relevant aspects in making our Final Determination.

Options for Deficit Recovery Payments for RP6

- 8.49 We considered regulatory precedents and decided upon two possible options for dealing with the established deficit repair allowances. It is important to note that consumers will pay for the pension deficit at some point, which means it comes down to a judgement on how quickly should deficit contributions be provided for. All of the options considered would be NPV neutral. Characteristics of the two potential options are set out below:

Option 1

- 8.50 NIE Networks have presented allowances for financial years to 2024 due to the increasing pension deficit. Option 1 would allow the Business Plan submission of NIE Networks to 2022 and also allowances for the years 2022-2024.
- 8.51 This option includes removal of the regulatory fraction. The regulatory fraction was set at 99.26% by the CC and NIE Networks also included adjustments for RP6 which increased the regulatory fraction above 100%. This option involves setting the regulatory fraction to 100%. This would simplify the proportions allocated to the regulatory activities going forward.
- 8.52 This option would have the benefit of providing sufficient funding to NIE to cover any foreseeable deficits, but NIE would have any surplus amounts removed at the time of the next price control, via a suitable mechanism.

	RP6 Request (£m)	RP6 DD (£m)
Pension Deficit Contribution	114.5	115.3
Pension ERDC disallowance	(30.5)	(30.5)
Net Amount Requested	84	84.8

Table 30: RP6 Option 1 allowances to 2022 and allowances 2022-4 with regulatory fraction set to 100% (in 2015-16 prices)

Option 2

- 8.53 This option would allow the Business Plan submission of NIE up until 2022, but give no further allowances to cover any deficits after this point and remove £25.1m from the NIE Networks submission.
- 8.54 This would also maintain alignment between the schemes' existing deficit recovery period and the period allowed for in RP5. In addition, in the event that future valuations lead to deficit payments being required beyond 31 March 2022, a mechanism already exists that will adjust for any differences in actual payments (although NIEN would have to finance the gap between 2022 and 2024).

- 8.55 We note that OFGEM have not followed this approach, of removing allowances mid price control, due to the fact that other schemes may have longer recovery periods which go beyond the existing control.

	RP6 Request (£m)	RP6 DD (£m)
Pension Deficit Contribution	114.5	80.0
Pension ERDC disallowance	(30.5)	(21.1)
Net Amount Requested	84	58.9

Table 31: RP6 Option 2 allowances- deficit recovery to 2022 only (in 2015-16 prices)

- 8.56 We recognise that the current funding position has worsened compared with expectations at the 2014 valuation – largely due to the performance of the scheme assets not keeping pace with the increasing value of the liabilities – however, fluctuations in the funding position (positive or negative) will happen in practice, and it is not certain that deficit contributions beyond 31 March 2022 will be necessary.
- 8.57 However, the historic deficit is still the consumers’ responsibility and it is a matter of timing as to whether the deficit is paid over a longer or shorter period and we must be mindful of the allocation of payments between current and future consumers.

Proposed Option for RP6

- 8.58 We are minded to adopt **Option 1** and include deficit recovery payments to 2022 and allowances for 2022-24. In addition, this option involves setting the regulatory fraction to 100% for RP6 and going forward (see below section).
- 8.59 The RP6 allowances for 2022-2024 will be reviewed for RP7 upon consideration of the outcome of the triennial reviews at 2017 and 2020 (also 2023, if available). At RP7 we will make a more informed decision as to whether these deficit recovery payments are required or should be adjusted. We note that, should the pension scheme be in surplus at RP7, we will make a negative adjustment to allowances granted for 2022-24. Any adjustment will be in NPV neutral terms.

Early Retirement Deficit Contribution (ERDC) disallowance

- 8.60 Between 1997 and 2003, when the NIEPS was in surplus, early retirement benefit enhancements were granted which increased the scheme’s liabilities, however, but no additional contributions were paid into the scheme at the time. At RP5, following extensive consideration, the CC decided that shareholders should fund part of these unfunded liabilities by disallowing 30% of deficit repair contributions (from a potential range of between 23% and 45%) allocated to the ‘Early Retirement Deficit Contribution’ (ERDC) element.

- 8.61 NIE Network requested allowances in their RP6 Business Plan with a negative adjustment of 30% to reflect ERDC proportion and explained the rationale for this in its Business Plan.
- 8.62 No further information has become available to present a robust case that a 30% allocation is inappropriate. Accordingly, we believe that it is reasonable to retain the 30% allocation.

Transmission and Distribution split

- 8.63 The CC set a split between pension costs of the business at the rate of 92/8 to the distribution and transmission businesses respectively. In its Business Plan submission and the PDAM methodology NIE Networks have adopted a split in the range of 76-77% to 23-24% approximately, which is dependent on the RAB allocation of the Transmission and Distribution businesses. We are content to apply NIE Network's proposed allocations based on the respective RABs of the Transmission and Distribution businesses as being reflective of the costs involved.

Proposed pension allowances and DD Approaches

- 8.64 We summarise our proposed approach to Pensions below:
- **Deficit separation** - We propose maintaining the CC methodology to allocate a deficit cut-off date of 31 March 2012 and that the established pre cut-off fund as being the consumers responsibility and the incremental post 31 March 2012 fund as being shareholders responsibility.
 - **ERDC disallowance**- we are minded to retain a 30% ERDC disallowance set by the CC to deficit recovery payments.
 - **Regulatory Fraction**- we propose removing the Regulatory Fraction for RP6 and going forward so that it represents a value of 100%. We do not propose to make a retrospective adjustment in relation to RP5 or other price controls.
 - **Transmission and Distribution splits** – we propose applying the approach used by NIEN in its business plan and allocate costs between the Transmission and Distribution businesses based on the RABs.
 - **Allowances to 2022**- we propose the allowances set by the CC in respect of deficit recovery payments from 2017 to 2022 in line with the amounts outlined in the CC FD with inflationary amounts added.
 - **Allowances 2022-24**- we are minded to include requested funding allowances in the last two years of RP6. These amounts are not guaranteed and will be considered at RP7, when they may be removed in NPV neutral terms, dependent on recent triennial valuations and deficit funding requirements.

RP6 proposed allowances

8.65 We present our proposed allowances compared to NIE Networks Business Plan. The proposed allowances are based on the above assumptions and we highlight that the allowances for 2022-24 are subject to review at RP7.

	RP6 Request (£m)	RP6 DD (£m)
Pension Deficit Contribution	114.5	115.3
Pension ERDC disallowance	(30.5)	(30.5)
Net Amount Requested	84	84.8

Table 32: Proposed UR DD pension deficit recovery (2015-16 prices)

8.66 This results in an annual profile as follows:

	10/2017- 03/2018	04/2018- 03/2019	04/2019- 03/2020	04/2020- 03/2021	04/2021- 03/2022	04/2022- 03/2023	04/2023- 03/2024
Pension deficit funding	8.867	17.736	17.736	17.736	17.736	17.736	17.736
Less ERDC disallowance (£m)	-2.3	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
Proposed RP6 pension allowance	6.567	13.036	13.036	13.036	13.036	13.036	13.036

Table 33: RP6 Pension DD Proposed allowance (2015-16 prices) with ERDC adjustment

8.67 It is proposed that this allowance will be allocated to the transmission and distribution businesses in the following proportions:

	10/2017- 03/2018	04/2018- 03/2019	04/2019- 03/2020	04/2020- 03/2021	04/2021- 03/2022	04/2022- 03/2023	04/2023- 03/2024
Transmission	23.64%	23.52%	23.47%	23.54%	23.46%	23.35%	22.82%
Distribution	76.36%	76.48%	76.53%	76.46%	76.54%	76.65%	77.18%

Table 34: Allocation of pension deficit recovery amounts between the distribution and transmission businesses

Areas of significance

- 8.68 In reviewing NIE Network pensions we are highlighting two areas we consider merit highlighting in this DD. These relate to pension scheme administration and expenses costs and potential pension scheme surpluses in the future. We outline our observations below.
- 8.69 We consider pension administration and investment expenses costs are higher than those for comparable companies and we would like to see NIE Networks to work collaboratively with pension scheme trustees to streamline and reduce such costs going forward. We expect to see a marked reduction in such costs and may consider significantly reducing allowances for such costs at future price controls. We have discussed this area in greater detail in the Pensions Annex at Annex F.
- 8.70 NIE Networks' pension scheme is currently in deficit. However, it is possible that the pension scheme may become a surplus in the future- for example if market conditions and / or gilts rates improve. NIE Networks should take appropriate action in the event of the pension scheme becoming into surplus and ensure the consumer benefits from any surplus. NIE Networks should indicate to the UR in a timely manner should the pension scheme be in surplus or that they consider it will be in surplus in the foreseeable future and make appropriate proposals to benefit the consumer.
- 8.71 We are considering the introduction of a 'Pension Monitoring Framework' (PMF) to ensure that NIE Networks only approaches the Utility Regulator when it is clear that there has been a substantial fall in the NIEPS funding position at triennial valuations during RP6, which in turn could lead to the possibility of materially higher deficit contributions. Conversely, to ensure a symmetric approach, this framework should also include an 'upside' PMF when the pension scheme funding has improved. We consider a 'downside' PMF may be appropriate at a level of 70% and a converse 'upside' PMF of 110%, The Utility Regulator will consider funding levels and pension scheme characteristics and future outlook to determine whether or not any adjustment is required to e.g. funding levels, deficit recovery payments (either up or down), bill adjustments, etc. We include additional detail on this proposed PMF within our Pension Annex F and we welcome views from respondents on this area.

9 Direct Network Investment

Direct Network Investment – Introduction

- 9.1 In this section of the draft determination, we assess NIE Networks proposals for direct network investment which forms part of the overall capital investment proposed by the company for RP6.
- 9.2 Direct investment are those activities which involve physical contact with network system assets such as refurbishment or reinforcement of existing assets and the creation of new assets. Other strands of investment not covered in this section include:
- i) Indirect expenditure associated with network investment covered in Section 5.
 - ii) Metering investment covered in Section 11.
- 9.3 Direct network investment is treated in one of two ways in this Price Control:
- i) investment for which an ex-ante allowance is included in this determination; and,
 - ii) investment carried out under the 'D5 mechanism' where an estimate included for costs which will be determined at a later date when the need for the project has been confirmed and the scope, cost and programme developed (see Section 13 beginning at paragraph 13.20 for a detailed description of the D5 mechanism).
- 9.4 In its business plan, NIE Networks proposed direct investment of £342.1m in the distribution network and £104.4m in the transmission network, a total of £446.5m over RP6 in 2015/16 prices. This included an estimate of the cost of three major transmission maintenance projects for which the allowances will be determined at a later date under the D5 mechanism.
- 9.5 This proposed investment is summarised by category in Table 35 and Table 36 for distribution and transmission respectively.

	RP5 Average per year	RP6 Average per year	RP6 Total
Distribution reinforcement	5.8	9.5	62.1
Distribution asset replacement	26.5	26.9	174.6
ESQCR	1.9	9.2	60
Other non-load	3.7	5.7	36.8
Network access and commissioning	1.5	1.3	8.7
Total distribution direct network investment	39.4	52.6	342.1

Table 35: NIE Networks proposed distribution direct network investment⁷²

	RP5 Average per year	RP6 Average per year	RP6 Total
Transmission reinforcement	9.2	0.2	1.0
Transmission asset replacement	13.7	15.7	102.1
Network access and commissioning	0.2	0.2	1.3
Total transmission direct network investment	23.2	16.1	104.4

Table 36: NIE Networks proposed transmission direct network investment⁷³

- 9.6 The summary information above is prior to the application of a frontier shift which takes account of the impact of real price effects on the rate of inflation experienced by NIE Networks and the potential for on-going productivity efficiencies, consistent with the presentation of proposals in the company's business plan.

Direct Network Investment Appraisal

- 9.7 Our detailed assessment of the company's proposed investment is set out in Annex O. The following section summarises key points from the appraisal.

Variance in run-rate of investment from RP5

- 9.8 In its business plan submission, NIE Networks compared the average annual rate of direct network investment in RP5 with that planned for RP6. Average annual expenditure in RP5 was estimated at £62.6m, increasing to £68.7m in RP6 (an increase of £6.1m or 9.7%). Much of the variance in expenditure from RP5 can be explained by five key areas identified in Table 37.

⁷² Source NIE Networks RP6 business plan 2017-2024, Table 9

⁷³ Source NIE Networks RP6 business plan 2017-2024, Table 34

	Annual average variance £m/a	Notes
Distribution reinforcement	3.7	The key drivers for increased distribution reinforcement are investment to cater for increasing use of low carbon technology (LCT such as electric vehicles) and to release capacity on the 33kV network for generation connections.
Distribution ESQCR	7.3	In RP5 NIE Networks carried out surveys to identify the parts of the network that did not comply with the Electricity Safety Quality and Continuity Regulations (ESQCR) introduced in 2012. In RP6 the company will begin to implement the compliance solutions.
Transmission reinforcement	-9.0	This comprises investment in D5 projects to address transmission system capacity or capability and generation cluster connection. The RP6 Business Plan only identified carry over investment for the completion of D5 projects begun in RP5. Further investment is expected in RP6 under the D5 mechanism including the North South Interconnector which is not included in this assessment (see section 13 for further details).
Transmission asset replacement		
Major maintenance projects	6.8	Investment in three major transmission network maintenance projects is planned for RP6. A preliminary estimate is included in the determination which will be replaced by an allowance determined under the D5 mechanism when the need, scope, programme and cost have fully assessed. Investment in RP5 was limited to preliminary development work on these projects.
General transmission assets	-4.7	NIE Networks has identified a reduction in refurbishment and replacement of general transmission assets in RP6.
Explained variance	4.1	
Other	2.0	
Total variance	6.1	

Table 37: Variance in annual average investment from RP5 to RP6

- 9.9 Much of the variance in the annual rate of expenditure between RP5 and RP6 can be explained by changes relating to new legislative and social drivers and specific major projects. The fact that the underlying annual rate of investment in refurbishment and replacement of the assets is relatively constant between RP6 and RP5 provides broad comfort as to the reasonableness of the company's proposals.

NIE Networks adjustments to the business plan prior to the draft determination

- 9.10 During our engagement on business plan submission, NIE Networks made a number of amendments to the proposed network investment in response to our challenge or based on its own assessment and updated information. This resulted in the total proposed direct network investment reducing by £22.1m.

UR appraisal of direct network investment

- 9.11 Our detailed assessment of the company's proposed investment is set out in Annex O. The annex includes sections for each category of work which consider:
- i) The type and scope of work covered.
 - ii) NIE Networks proposals for investment including the volume and cost of work.
 - iii) The Utility Regulator's draft determination, including any challenge made to the volume of work proposed by the company or its estimated cost of the work.
- 9.12 During RP5 we introduced annual cost reporting against Regulatory Instructions & Guidance (RIGs) to provide information on delivery of the current price control and to provide information to benchmark and challenge future business plans. In respect of direct network investment these reports include:
- 9.13 Network Investment RIGs reporting which report costs and outputs against the allowances identified by the Competition Commission in its final determination for RP5.
- 9.14 Cost & Volume RIGs report costs and volumes of the replacement and refurbishment of individual work items such as transformers, switchgear, poles, towers and conductors further divided by voltage. These Cost & Volume RIGs are structured to reflect data collected on GB DNOs by Ofgem with a view to benchmarking NIE Networks costs.
- 9.15 The Cost & Volume RIGs submitted to date have been heavily qualified by NIE Networks in relation to the level of retrospective allocation necessary to complete reports back to 2012-13. In addition, the company was not able to provide a robust allocation of its estimated costs for network investment in RP6 against Cost & Volume categories. As a result, we have relied on reported costs and outputs reported in the Network Investment RIGs in the first four years of RP5 as the basis of challenging costs for RP6. Where possible we have attempted to test the efficiency of NIE Networks proposed investment using cost and volume reporting but the qualifications placed on these reports has limited this type of analysis. We expect the company to develop and present a comprehensive assessment of Cost & Volume reports to support comparative efficiency analysis from 2017/18 and to be capable to include a Cost & Volume submission in its RP7 business plan submission cross referenced to the Network Investment RIGs submission.
- 9.16 The outcome of our assessment of direct network investment is summarised in Table 38 which includes a comparison of the business plan submission and draft determination before the application of the frontier shift and the draft determination post frontier shift.

	6 months to Mar-18	18/19	19/20	20/21	21/22	22/23	23/24	Total RP6
NIE Networks direct network investment (pre frontier shift)								
Distribution	29.1	52.1	52.2	52.2	52.2	52.2	52.3	342.1
Transmission	10.2	17.5	17.2	19.2	16.0	16.0	8.5	104.4
	39.3	69.6	69.4	71.4	68.2	68.2	60.8	446.5
UR draft determination of direct network investment (pre frontier shift)								
Distribution	23.3	46.7	46.7	46.7	46.7	46.7	46.7	303.4
Transmission	4.9	15.1	23.1	21.5	14.7	14.7	7.2	101.2
	28.2	61.8	69.8	68.2	61.4	61.4	53.9	404.6
Frontier shift factor	0.974	0.961	0.953	0.948	0.943	0.939	0.934	
UR draft determination of direct network investment (post frontier shift)								
Distribution	22.7	44.9	44.5	44.2	44.0	43.8	43.6	287.8
Transmission	4.8	14.5	22.0	20.4	13.9	13.8	6.7	96.1
	27.5	59.4	66.5	64.6	57.9	57.6	50.3	383.8

Table 38: Determination of direct network investment

- 9.17 The change in network investment from the business plan submission to the draft determination before the application of frontier shift is summarised in Table 39.

	Distribution	Transmission	Total
NIE Networks Business Plan submission	342.1	104.4	446.5
Less D5 estimates included in the investment plan	-4.3	-48.3	-52.6
Less D57 LCT funding held for Mid-term Review	-10.5	0.0	-10.5
Business plan core investment net of estimates	327.3	56.1	383.4
Confirmed adjustments by NIE Networks post engagement	-12.6	-8.5	-21.1
Business plan core investment net of post engagement adjustments	314.7	47.6	362.3
UR adjustments to the core investment plan	-26.1	0.0	-26.1
Draft determination of core investment plan	288.6	47.6	336.2
Add back D5 estimates included in the investment plan	4.3	53.6	57.9
Add back D57 LCT funding held for Mid Term Review	10.5	0.0	10.5
Draft determination including D5 estimates included in the business plan submission.	303.4	101.2	404.6

* We increased the estimated cost of BPS - Castlereagh (T601) project based on NIE Networks revised submission

Table 39: Change in direct network investment from the business plan submission to the draft determination

- 9.18 In its business plan the company identified £383.4m of direct network investment net of D5 project estimates. The company subsequently identified a reduction of £21.1m on this sum as a result of further investigations and engagement with UR. The draft determination represents a further reduction of £26.1m, a total reduction of £47.2m (12.3%) from the business plan submission net of uncertainty amounts.
- 9.19 The majority of reductions are as a result of unit cost adjustments based on RP5 outturn costs. However we have adjusted some of the RP6 volumes based on RP5 run-rates and, in some cases, due to insufficient justification in the RP6 Network Investment Plan.

D5 projects

- 9.20 In its final determination for RP5, the Competition Commission defined a “D5 Mechanism” to allow for additional investment projects to increase the capacity and capabilities of NIE’s transmission system. The details of the mechanism are set out in the RP5 final determination from paragraph 5.246.⁷⁴.
- 9.21 Under the D5 mechanism an ex-ante allowance is not determined at the price control but the determination is made at a later date when the need for the project has been confirmed and the scope, cost and programme developed.

RP5 D5 project carry over

- 9.22 An allowance for one network investment project was determined in RP5, the Omagh Tamnamore 3rd circuit at £21.865m in 2015/16 prices. This allowance has been profiled in proportion to the current estimated expenditure profile reported by the company in response to a query on the business plan.
- 9.23 The company’s current estimate is that £1.0m of this investment will be made in the first year of RP6. This has been taken into account in our analysis for RP6 pending confirmation of actual expenditure which will be used in the calculation of future tariffs.

Asset maintenance projects under the D5 mechanism

- 9.24 In principle, the D5 mechanism was developed for additional projects required to increase the capacity or capability of the transmission system, in effect, projects which will be promoted by SONI as the Transmission System Operator. However, in its determination for RP5 the Competition Commission extended this approach to two major transmission refurbishment projects for which the scope, cost and programme had not been well defined: Ballylumford Switchboard and Coolkerragh - Magherafelt transmission line refurbishment. Neither of these projects have been undertaken in RP5 and NIE Networks now plans to undertake the work in RP6.

⁷⁴https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

- 9.25 In RP6 we propose including the following transmission asset maintenance projects or major distribution projects within the scope of the D5 mechanisms:
- i) The Ballylumford switchboard and Coolkerragh-Magherafelt transmission line refurbishment included by the Competition Commission in RP5.
 - ii) The Ballylumford to Castlereagh transmission line refurbishment project. The company provided an estimate for the refurbishment of this circuit in its business plan submission but has since identified a major risk associated with the existing foundations following similar investigations on the Coolkerragh-Magherafelt transmission line refurbishment project. In addition, the refurbishment project may be subsumed into a transmission capacity project.
 - iii) Two distribution reinforcement projects, Armagh Main and Airport Road where the scope and cost of the distribution project could be materially impacted by potential transmission capacity projects which might be carried out under the D5 mechanism.
- 9.26 While the allowance for these maintenance projects will be determined at a later date, we have included an indicative allowance of £58.9m for these projects within the RP6 determination as shown in Table 40, consistent with the approach adopted by the company in its Business Plan submission. During RP6, these allowances will be replaced with the actual allowances determined under the D5 mechanism.

Project	Direct investment included in RP6 (£m)
Ballylumford Switchboard	16.0
Coolkeeragh - Magherafelt	25.8
Ballylumford - Eden - Carnmoney - Castlereagh	11.8
Armagh Main distribution reinforcement	1.6
Airport Road distribution reinforcement	2.7
	57.9

Table 40: Defined D5 projects

- 9.27 However, we note our concern that these projects are not sufficiently well developed to allow us to determine efficient ex-ante allowances in this determination. While there is a case of determining allowances at a later date under the D5 mechanisms where the scope, cost and programme are not well defined, this should not be viewed as the norm. It is for the company to plan development work on this type of project to ensure that, where possible, ex-ante allowances can be included in the Price Control determination rather than delayed to a later date.

Transmission capacity and capability projects under the D5 mechanism

- 9.28 In its business plan, NIE Networks list 15 potential transmission network reinforcement projects identified by SONI with an estimated total value of £250m. These were not included in the £446m of planned investment in the company's

business plan for RP6 and would represent an increase of 56% over the planned network investment.

- 9.29 The company highlighted the uncertainty over this investment which is subject to further assessment by SONI to confirm need and allow the development of a solution, scope and cost estimate. To highlight this uncertainty, the potential investment of £250m in RP6 should be compared with investment of £22m in one project determined under the D5 mechanism in RP5 to date.
- 9.30 We also sought the advice of SONI in respect of this potential investment. SONI provided a lower bound estimate of potential investment of £230m. However, SONI also highlighted the need for future work to confirm the need, scope and cost of this work.
- 9.31 While we recognise the uncertainty associated with D5 investment, we considered it prudent to estimate how this type of investment might affect tariffs in RP6 so that consumers could be aware of its impact. In doing so we have taken account of the fact that D5 investment might include the North-South Interconnector pending the outcome of the on-going public inquiry. We have taken account of the list of projects and estimates of potential investment provided by NIE Networks and SONI and our own high level estimates. Based on this we concluded that it is appropriate to test tariffs in RP6 for £200m of additional investment under the D5 mechanism. The outcome of this analysis is shown in paragraph 12.73.

‘Optional’ Investment Plan

- 9.32 In its business plan, the company identified a further £45.4m of investment which is categorised as ‘optional’ which it did not include in its plans for RP6. This investment is summarised in Table 41.

	Optional investment £m	Notes
Investment to strengthen the 11kV overhead line network.	25.6	Phased replacement of 25mm conductors on the spine of the 11kV overhead line network with 50mm conductors to address capacity and potential failure under ice loads.
Additional investment to improve flood resilience.	2.6	Improved flood resilience at 200 sites which serve 4000 consumer.
Accelerated resilience tree cutting.	0.7	Resilience tree cutting will reduce the risk of falling trees causing damage to the network. The optional investment is to accelerate resilience tree cutting over a period of 20 years rather than the planned 25 years.
Further investment to reduce unplanned power cuts.	16.5	The company suggested that investment in additional generators (£1.0m) and investment in additional dedicated resources available for fault and emergency response (£11.5m) would reduce the 5000 homes and businesses experiencing a power cut of over 10 hours by 25%. Investment of a further £5.0m improving circuits serving worst served customers would (those affected by 6 or more power cuts in an 18 month period) by 20%.
Total 'optional' investment	45.4	

Table 41: Optional network investment proposed by NIE Networks

9.33 The company presented these programmes of investment as optional⁷⁵:

“because the investments received mixed levels of support during our customer and stakeholder engagement process. Domestic customers surveyed were generally supportive of the programmes and willing to pay for improvements, whilst business customers supported improvements in principle but the majority were not willing to pay for these improvements.”

“given other competing priorities in our core plan, we have decided to include these projects as optional.”

9.34 We note the company's view that this investment is optional because they are not fully supported by consumer engagement and because of the other competing priorities in the core plan. It is for the company to assess the needs of its consumers including their willingness to pay and the balance of competing priorities in its business plan. In view of this, we have not included this investment in the draft determination. Direct network investment outputs and incentives and uncertainty mechanisms.

Investing for the future

9.35 In its business plan NIE Networks proposed investment of £10.48m under the heading “investing for the future”. The underlying justification of this investment is the trialling and integration of technologies which could offer an economic solution if network load is increased by the uptake of low carbon technology.

⁷⁵ Source NIE Networks RP6 business plan 2017-2024, 8.2 and 8.3

- 9.36 Six projects were proposed which build on the results of general industry development and specifically on innovation projects being undertaken in GB through the Ofgem Electricity Network Innovation Competition. A common theme of these projects is the use of communication technology and automated control systems to manage load, voltage levels and network configuration in real time. This is a significant departure from a 'static' network where the capacity is set at pre-defined limits determined on the most onerous design conditions and the configuration is set and can only be varied manually.
- 9.37 We understand that the company's intent is not to undertake leading edge innovation but to trial successful innovation which could have widespread application and ensure that:
- i) It can successfully integrate the technology in its network, identifying and addressing interface issues and product specification.
 - ii) Obtain or develop the systems and software necessary to receive and analyse information from the network and manage the network in real time.
- 9.38 We have reviewed the company's proposals and concluded that much of the work proposed has potential. We have deducted indirect costs from the submission as these are covered under the general indirect costs set out in Section 5. Our draft determination includes an allowance of £7.26m in respect of investing in the future trials.
- 9.39 However, we have concluded that there is further work to do to confirm that the projects proposed will deliver value and that the company should complete this work and submit the results to us before embarking on the procurement of assets and systems and the trials themselves. For example:
- i) The cost benefit analysis submitted by the company to support the work proposed addressed the application of the technology in a single case assuming that the trial had been successful. The company should assess the potential application of each type of technology it proposes to trial, take account of the risk of the trial not being successful and consider the net-present value of the costs and benefits over the life of the relevant assets.
 - ii) In its submission, the company has highlighted technical issues which arose in some of the innovation projects carried out in GB which do not appear to have been resolved. The company should show how these technical issues can be resolved either within or outwith the proposed trial.
 - iii) The scope of works which the trials will deliver should be confirmed. For example, whether all software and systems necessary to manage information flow will be procured during the trials or whether additional procurement will be required. This should be built into the cost benefit analysis described above.
 - iv) The company has noted that the trials will be carried out on assets which are not at the limit of load because the company cannot yet confirm that the

solution being trialled will work. Where an immediate solution is necessary a 'traditional' asset replacement or reinforcement is planned. However, the company should show that the trials it plans to carry out can fully test the equipment and systems over a full range of operating conditions allowing them to be applied in practice.

- v) While the company does not plan to use the trial work as a means of delivering RP6 planned network investment outputs, we expect the company to deliver the solutions outlined in the programme of work as permanent solutions which could provide benefit in the long term.
 - vi) The company should set out the programme for the trials. We would expect the trials to inform the assessment of the LCT load reopener set out in Section 13 beginning paragraph 13.75.
 - vii) In general, the trials should be sufficient to inform future application. It should address the generic technology (as opposed to the specific type tested). It should be complete in that any recommendations for further research necessary to implement the trials should be carried out under the RP6 allowance subject to the cost risk sharing mechanism.
- 9.40 Once we have considered NIE Networks views on these issues and further detail on its projects we will incorporate these into our final determination, including setting out the structure of the allowances and consideration of what incentive NIE Networks should have to deliver successful projects.
- 9.41 Our initial view is that the company would have freedom to amend its proposals for the trials undertaken in RP6 within the allowance for trial projects provided it demonstrates that the additional projects are of equal or greater value than those initially proposed.
- 9.42 These trial projects would be subject to the cost risk sharing mechanism but not the substitution mechanism. If the company decides not to undertake a project, this would be treated as deferral.

10 Frontier Shift

Real price effects

- 10.1 The price of a company's various inputs may differ over time. Price controls have normally been indexed by the Retail Prices Index (RPI) to account for broad changes in prices. However, being a measure of general inflation, not all types of cost changes will be reflected in the range of prices used to calculate the RPI.
- 10.2 To account for this it has become common regulatory practice to calculate and make adjustments for the difference, either positive or negative, between particular input price changes for a company or industry and the general (RPI) measure of inflation. This adjustment is described as *real price effects* (RPEs).
- 10.3 RPEs are designed not to be straight pass through of costs but rather a proxy of cost pressures expected. They also sit within the context of the wider efficiency challenge of the company subject to price control.

Productivity shift

- 10.4 A company can become more efficient over time and so close the gap between its efficiency level and that of the economic frontier. Equally, the industry's overall efficiency or frontier can change over time. It is possible the most efficient company in an industry can find new or improved ways of using less input volumes to maintain current output levels.
- 10.5 In addition to the real price effects described previously, it is necessary to apply a productivity assumption to opex and capex so as to take account of continuing efficiencies which the industry can achieve over the price control period. This is a base level of efficiency which even frontier companies would be expected to achieve as they continually improve their business over time. For example with the use of new technologies, new working practices or other means to enable their businesses to run more efficiently.

Frontier shift profile at RP6

- 10.6 The frontier shift in real terms is calculated by applying the average annual productivity figure (1.0%) to the real price effects result. The real price effect figure is computed from discounting RPI from the weighted impact of nominal input prices.⁷⁶ The net impact of frontier shift for opex and capex is shown in Table 42: Opex Frontier Shift and Table 43: Capex Frontier Shift below. Please note numbers may not sum due to rounding and 2016/17 is as determined by the CC at RP5.

⁷⁶ For example for 2016/17 the opex frontier shift is calculated as follows: $(1.025/1.022) \times (1 - 0.01) - 1 = -0.4\%$. When applied to gross opex and capex these numbers are transformed into a *frontier shift multiplication factor* by subtracting from 100% i.e. the cumulative 5.8% becomes (100% minus 5.8%) = 94.2% or a factor of 0.942.

- 10.7 For the RP6 draft determination we are assuming a cumulative frontier shift of 5.8% for opex in total over the 6.5 years of the price control. This is calculated from yearly frontier shift assumptions that are relatively higher in the first 2 years but then more moderate, tailing off for the rest of RP6.
- 10.8 For capex we estimate a similar profile of frontier shift change, starting relatively higher then tailing off after the first 2 years. This gives a cumulative frontier shift of 6.6% for capex in total for the 6.5 years. The impact of the frontier shift on NIE Network's opex and capex cost base is shown at the last line of each table.
- 10.9 In summary, the frontier shift process combines nominal input price forecasts with productivity expectations and RPI inflation. The frontier shift in real terms can be represented in a simple way as follows:
- $$\text{Frontier shift in real terms} = \text{input price increase} \text{ minus } \text{forecast RPI (measured inflation)} \text{ minus } \text{productivity increase}$$
- 10.10 A more detailed explanation of our real price effects and productivity analysis can be found in Annex C – Frontier Shift: real price effects & productivity.

		Opex								
UR draft determination										
Opex	Weight	RP5			RP6					
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Labour	77.3%	2.6	2.6	2.7	3.1	3.3	3.7	3.9	3.9	3.9
Materials	7.7%	2.5	2.5	2.5	3.0	3.5	3.9	3.9	3.9	3.9
Equipment/Plant	0.0%	1.3	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Other	15.0%	1.1	2.2	3.9	3.4	3.1	3.1	3.2	3.2	3.2
Total nominal input price inflation		2.4	2.5	2.8	3.2	3.3	3.7	3.8	3.8	3.8
RPI		1.1	2.2	3.9	3.4	3.1	3.1	3.2	3.2	3.2
Productivity growth		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Frontier shift (from base year)		0.0	-0.4	-1.7	-1.3	-0.8	-0.5	-0.4	-0.4	-0.4
Frontier Shift (%)		0.0%	0.4%	1.7%	1.3%	0.8%	0.5%	0.4%	0.4%	0.4%
Frontier Shift (Cumulative %)		0.0%	0.4%	2.1%	3.3%	4.1%	4.6%	5.0%	5.4%	5.8%
Efficiency effect on cost base - opex		100.0%	99.6%	97.9%	96.7%	95.9%	95.4%	95.0%	94.6%	94.2%

Table 42: Opex Frontier Shift

		Capex								
UR draft determination										
Capex	Weight	RP5			RP6					
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Labour	52.8%	2.7	2.6	2.7	3.1	3.3	3.7	3.9	3.9	3.9
Materials	30.2%	2.5	2.5	2.5	3.0	3.5	3.9	3.9	3.9	3.9
Equipment/Plant	5.9%	1.3	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Other	11.1%	1.1	2.2	3.9	3.4	3.1	3.1	3.2	3.2	3.2
Total nominal input price inflation		2.4	2.5	2.7	3.0	3.3	3.6	3.7	3.7	3.7
RPI		1.1	2.2	3.9	3.4	3.1	3.1	3.2	3.2	3.2
Productivity growth		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Frontier shift (from base year)		0.0	-0.6	-2.0	-1.4	-0.8	-0.5	-0.5	-0.5	-0.5
Frontier Shift (%)		0.0%	0.6%	2.0%	1.4%	0.8%	0.5%	0.5%	0.5%	0.5%
Frontier Shift (Cumulative %)		0.0%	0.6%	2.6%	3.9%	4.7%	5.2%	5.7%	6.1%	6.6%
Efficiency effect on cost base - capex		100.0%	99.4%	97.4%	96.1%	95.3%	94.8%	94.3%	93.9%	93.4%

Table 43: Capex Frontier Shift

11 Market Operations and other activities

Metering

Introduction

- 11.1 NIE Networks (NIE Networks) submission for metering services is contained within their Market Operations Business Plan. The submission covers activities relating to the Meter Installs/Changes and Meter Recertification programmes, meter reading and other operating costs and overheads, such as Information Technology (IT), Human Resources (HR) and finance costs, which have been allocated to metering.
- 11.2 The Market Operations Business Plan also refers to 'Other costs' which relate to Transactional and Revenue Protection Services. Transactional Services refers to the provision by NIE Networks of services to suppliers in support of the competitive retail market. Revenue Protection Services refers to NIE Networks' activities to detect and deter cases of illegal abstraction of electricity (i.e. electricity theft) and to assist suppliers in relation to that illegal abstraction. As these incidents are largely related to electricity theft from meter tampering we have considered Revenue Protection within this metering section.
- 11.3 NIE Networks' submission and Utility Regulator's proposed draft determination for the total costs (15/16 prices) relating to these activities are set out in Table 37.
- 11.4 We have provided a detailed breakdown of the figures together with commentary for the relevant metering activities in Annex N - Metering.

	Oct 17- Mar 18	Apr18- Mar19	Apr19- Mar20	Apr20- Mar21	Apr21- Mar22	Apr22- Mar23	Apr23- Mar24	Total, £m
<u>NIE Networks Submission</u>								
TOTAL	8.87	15.96	14.86	14.77	14.33	14.46	14.20	<u>97.45</u>
TOTAL (excluding capex direct costs)	4.24	8.57	8.65	8.68	8.71	8.94	8.78	<u>56.58</u>
<u>Utility Regulator Draft Determination</u>								
TOTAL	8.19	14.53	13.16	13.04	12.71	12.66	12.54	<u>86.83</u>
TOTAL (excluding capex direct costs)	3.62	7.25	7.26	7.26	7.26	7.30	7.26	<u>47.19</u>
Difference in Totals								<u>10.62</u>
Difference in Totals (excluding direct costs)								<u>9.38</u>

Table 44: Summary of NIE Networks Market Operations Business Plan Submission and Utility Regulator Draft Determination

Smart Metering

- 11.5 NIE Networks have made no provision for a smart metering roll-out in their business case submission which we view as appropriate. At this stage there are no plans for a

smart meter roll-out in Northern Ireland within the price control period. The Department for Economy are the government department responsible for a decision on whether a smart meter roll-out will be required.

Utility Regulator Approach

- 11.6 The approach taken for the RP6 metering programmes continues with a volume driven allowance and a set unit cost for each type of meter installation as adopted in RP5. This has been applied to all metering programmes in RP6.
- 11.7 Where possible we have assessed forecasted costs for RP6 against the actual costs incurred for the provision of similar services under RP5. We have facilitated this approach by using the Metering and Financial RIGS. This approach is also consistent with the overall approach of the RP6 price control.
- 11.8 For some work areas a direct comparison has not been possible between the costs that NIE Networks are forecasting for RP6 and the costs they incurred for RP5. For example costs for the Meter Recertification programme were only incurred in the last year of RP5 as the programme commenced. We have made provision in the draft allowances where relevant.
- 11.9 We have accepted NIE Networks' business case submission where their submitted forecast costs for RP6 are lower than the actual costs presented in the RIGS.

Meter Installs/Changes Programme

- 11.10 Meter Installs/Changes relates to the metering services for installing, exchanging and alteration of electricity meters at the request of electricity suppliers. The capital costs of the Meter Installs/Changes programme are addressed in this section. This includes both the direct and indirect costs related to the meter installs/changes programme.
- 11.11 Direct costs are the costs of the actual meter and its installation whereas the indirect costs are the costs incurred for the management/co-ordination of the programme.
- 11.12 There is no change between NIE Networks' proposed direct costs for Meter Installs/Changes and the Utility Regulator's draft determination. We accept the units costs submitted as they are in line with RP5 actuals and have reduced since the CC determination. We have proposed to accept NIE Networks' submitted indirect costs but we will consider further whether we should apply a catch up efficiency in line with results of our IMF & T benchmarking.

Meter Installs/Changes	Oct-17	Apr-18	Apr-19	Apr-20	Apr-21	Apr-22	Apr-23
	Mar-18	Mar-19	Mar-20	Mar-21	Mar-22	Mar-23	Mar-24
Meter Installs/Changes							
Direct Costs	1.42	2.85	2.85	2.85	2.85	2.85	2.85
39% of Indirect Costs allocated to capex	0.21	0.42	0.42	0.42	0.42	0.42	0.42

Table 45: Utility Regulator Draft Determination for Meter Installs/Changes Programme

Meter Recertification Programme

- 11.13 Meter Recertification relates to NIE Networks' statutory obligations to use meters that remain within a certified period. As such NIE Networks are required to replace a meter when it reaches the end of its prescribed certification life.
- 11.14 We have accepted all of the proposed unit costs for the recertification metering programme, except for the recertification of credit meters where we are seeking further information. On the whole the unit costs have reduced from CC determination and are in line with actuals.
- 11.15 We are not proposing any changes to NIE Networks' submitted indirect costs for recertification.
- 11.16 NIE Networks' submission for meter replacement for theft totalled 24,400 meters split over RP5 and RP6. We have limited this to 20,000 meters in total to be split across RP5 and RP6.

	Oct-17	Apr-18	Apr-19	Apr-20	Apr-21	Apr-22	Apr-23
Meter Recertification & Theft	Mar-18	Mar-19	Mar-20	Mar-21	Mar-22	Mar-23	Mar-24
Meter Recertification:							
<i>Direct Costs</i>	2.70	3.99	3.05	2.93	2.60	2.52	2.43
<i>39% of Indirect Costs allocated to capex</i>	0.05	0.09	0.09	0.09	0.09	0.09	0.09
Meter Replacement for Theft	0.450	0.450	0.000	0.000	0.000	0.000	0.000

Table 46: Utility Regulator Draft Determination for Meter Recertification and Theft

Metering Overheads

- 11.17 Metering Overheads are the operating costs that support the delivery of metering services which have been allocated to capex. They comprise the following: Fault and Emergency; IT, Stores and Safety; and Finance and HR costs.
- 11.18 These costs are apportioned to:
- Metering – Allocation of overhead and admin
 - Market Opening – Allocation of overhead and admin
 - Meter Reading - Allocation of overhead and admin
- 11.19 As per our approach we have assessed the metering overheads for each of the three areas against the actuals that have been incurred for RP5.
- 11.20 There is a significant difference between our proposed allowance of £2.629m and NIE Networks' submission of £5.178m over the price control period. From the information submitted by NIE Networks we are not clear why there is such a difference between the costs that have been incurred in RP5 compared to those forecast in RP6 for this area.

11.21 We accept that there are new work programmes within RP6 that will not have been fully reflected within the actuals incurred for RP5 such as the meter recertification programme. We have however included the indirect costs for this programme but we do not see how the addition of these programmes would increase the overheads significantly.

11.22 We have asked NIE Networks to provide their reasoning for why costs have increased in this area. We will consider any new information in our assessment; however for the reasoning above we consider that the actuals incurred under RP5 form a consistent basis for future costs in this area.

Metering Overheads	Oct-17	Apr-18	Apr-19	Apr-20	Apr-21	Apr-22	Apr-23	Total £m
	Mar-18	Mar-19	Mar-20	Mar-21	Mar-22	Mar-23	Mar-24	
Metering – allocation of overhead and admin	0.202	0.404	0.404	0.404	0.404	0.404	0.404	2.629
Market Opening – Allocation of overhead and admin	0.065	0.132	0.134	0.134	0.134	0.142	0.134	0.874
Meter Reading – Allocation of overhead and admin	0.151	0.307	0.312	0.312	0.312	0.332	0.312	2.039
Total	0.418	0.843	0.850	0.850	0.851	0.879	0.851	5.541

Table 47: Utility Regulator Draft Determination for Metering Overheads

Allocation of administrative costs

11.23 Allocation of administrative costs refers to the operating costs that support the delivery of metering services which have been allocated to opex. They comprise the following: Fault and Emergency; IT, Stores and Safety; and Finance and HR costs. They also contain a proportion of the indirect costs for the metering programmes.

Administrative Costs	Oct-17	Apr-18	Apr-19	Apr-20	Apr-21	Apr-22	Apr-23	Total £m
	Mar-18	Mar-19	Mar-20	Mar-21	Mar-22	Mar-23	Mar-24	
Metering Services: Allocation of administrative costs total	0.64	1.29	1.29	1.29	1.29	1.29	1.29	8.37
<i>Metering services: Allocation of administrative costs</i>	<i>0.57</i>	<i>1.14</i>	<i>1.14</i>	<i>1.14</i>	<i>1.14</i>	<i>1.14</i>	<i>1.14</i>	7.43
<i>61% of Indirect costs - Meter Recertification</i>	<i>0.07</i>	<i>0.14</i>	<i>0.14</i>	<i>0.14</i>	<i>0.14</i>	<i>0.14</i>	<i>0.14</i>	0.94
Market Opening: Allocation of administrative costs	0.10	0.20	0.21	0.21	0.21	0.22	0.21	1.36
Meter Reading: Allocation of administrative costs	0.24	0.49	0.49	0.49	0.49	0.49	0.49	3.16
Total	0.98	1.98	1.99	1.99	1.99	1.99	1.99	12.89

Table 48: Utility Regulator Draft Determination for administrative costs

Meter Reading

11.24 NIE Networks collect and process meter reading data for all c. 860,000 customer premises throughout Northern Ireland. A small proportion of this data can be obtained remotely from meters at c. 10,000 commercial and industrial premises. However the vast proportion of meters is read manually by NIE Networks meter reading staff.

11.25 We consider that meter reading is a business as usual activity. As such we expect that any opportunities to improve performance would be limited so therefore propose to continue with the costs that were reported within the RIGs.

11.26 In their submission NIE Networks note that the number of meter reads will rise as their customer base increases over the RP6 period. We do not see that there will be a year-on-year increase as suggested by NIE Networks. We are of the view that NIE Networks have not provided evidence to support their proposed 0.8% increase.

Meter Reading	Oct-17	Apr-18	Apr-19	Apr-20	Apr-21	Apr-22	Apr-23	Total £m
	Mar-18	Mar-19	Mar-20	Mar-21	Mar-22	Mar-23	Mar-24	
Meter Reading	1.76	3.52	3.52	3.52	3.52	3.52	3.52	22.88

Table 49: Utility Regulator Draft Determination for Meter Reading

Metering Maintenance

11.27 Metering maintenance covers the following activities:

- **Faults and emergency work** which relates to NIE Networks staff reports of meter faults, in particular to faults that have led to an interruption of supply.
- **Meter inspection** costs

11.28 We have accepted NIE Networks' submission for faults and emergency work. However we have not accepted NIE Networks' proposal to train meter readers to carry out remedial works on premises. We consider that the expected savings should cover the costs in any changes to work practices in this area.

Meter Maintenance	Oct 17- Mar 18	Apr18- Mar19	Apr19- Mar20	Apr20- Mar21	Apr21- Mar22	Apr22- Mar23	Apr23- Mar24	RP6 Total
Meter Inspection RP5 actual	0.033	0.067	0.067	0.067	0.067	0.067	0.067	0.434
Fault and Emergency	0.253	0.507	0.507	0.507	0.507	0.507	0.507	3.295
Total	0.287	0.574	0.574	0.574	0.574	0.574	0.574	3.729

Table 50: Utility Regulator Draft Determination for Meter Maintenance

Other operating costs relating to keypad meters

11.29 Other operating costs relating to the costs incurred for operating the IT infrastructure supporting keypad meters. We have accepted NIE Networks' submission for this activity; however we seek further information from NIE Networks to provide reasoning why there is a forecast reduction of costs in this area compared to the RIGS data.

Other operating costs relating to keypad meters	Oct 17- Mar 18	Apr18- Mar19	Apr19- Mar20	Apr20- Mar21	Apr21- Mar22	Apr22- Mar23	Apr23- Mar24	RP6 Total
Other operating costs relating to keypad meters	0.053	0.105	0.105	0.105	0.105	0.105	0.105	0.683

Table 51: Utility Regulator Draft Determination for operating costs to keypad meters

Revenue Protection Services

11.30 NIE Networks carry out revenue protection activities to prevent, detect and investigate energy theft. Our draft determination is based on the actual costs incurred presented in the RIGS.

Revenue Protection Services	Oct 17- Mar 18	Apr18 Mar19	Apr19 Mar20	Apr20 Mar21	Apr21 Mar22	Apr22 Mar23	Apr23 Mar24	RP6 Total
Revenue Protection	0.24	0.47	0.47	0.47	0.47	0.47	0.47	3.06
Revenue Protection Income	-0.17	-0.34	-0.34	-0.34	-0.34	-0.34	-0.34	-2.23

Table 52: Utility Regulator Draft Determination for Revenue Protection Services

11.31 NIE Networks have proposed a new incentive scheme to include all unbilled units resulting from illegal abstraction rather than just those from premises that are not registered with a supplier. However we do not agree with the proposed scheme. It is our view that the proposed arrangement could have an unintended consequence contrary to the aim of the proposed scheme. Our reasoning is set out further in the RP6 Incentive Mechanisms section.

Transactional Services

11.32 Transactional Services refers to the provision by NIE Networks of services to suppliers in support of the competitive retail market. These charges apply to metering fieldwork services and to a range of non-fieldwork activities.

11.33 We have reviewed the costs and revenues provided in the RIGS data for Transactional Charges. Our draft determination is based on the actual costs presented in the RIGS.

Transactional Services	Oct 17- Mar 18	Apr18 Mar19	Apr19 Mar20	Apr20 Mar21	Apr21 Mar22	Apr22 Mar23	Apr23 Mar24	RP6 Total
Transactional Charges	0.15	0.30	0.30	0.30	0.30	0.30	0.30	1.93
Transactional Income	-0.36	-0.71	-0.71	-0.71	-0.71	-0.71	-0.71	-4.62

Table 53: Utility Regulator Draft Determination for Transactional Services

Contestability

- 11.34 We have been taking steps to introduce contestability in electricity network connections.
- 11.35 In 2015 the Utility Regulator asked NIE Networks to prepare for the introduction of contestability and a project was set up. In May 2016, NIE Networks implemented contestability in connections for customers with a capacity of more than 5M. It plans to introduce contestability for remaining customers by the end of March 2018.
- 11.36 As the network owner NIE Network's systems and processes have been developed based on all alterations being performed by their own business. To provide for the introduction of contestability changes are required to many of the corporate IT systems and employee working practices.
- 11.37 NIE Networks has indicated that £5.994m is required for external costs to deliver the changes to their systems and processes. We have asked our consultants to review NIE Networks expenditure and we have determined that an allowance of £4.764m should be adequate for NIE Networks to introduce contestability IT systems and employee working practices.
- 11.38 The following table summarises the analysis.⁷⁷ It sets out NIE Networks proposed allowance, and our counter-proposal (including the breakdown of our proposed allowance relating to costs incurred in RP5 and costs expected in RP6).

Cost category	NIE proposal total	UR proposal total (RP5 + RP6)	UR proposal: RP5	UR proposal: RP6 (Oct 2017 – Mar 2018)
	£k	£k	£k	£k
External Resources	2841	2592.3	1995.6	596.7
IT Expenditure	2327	1877	1402	475
Miscellaneous	426	295	169	126
Total External Costs	5594	4764.3	3566.6	1197.7

Table 54: IT contestability

- 11.39 We welcome views on our proposed allowance. We also welcome views and evidence on whether this allowance should be recovered from the DUoS customers or new electricity connection customers.
- 11.40 If costs are to be recoverable from DUoS customers, we propose that costs (both capital expenditure and operational expenditure) should be treated as capital

⁷⁷ We plan publish our consultancy report analysis during the RP6 DD consultation period.

expenditure and should be allocated to a 5 year Distribution RAB. We would make an opening RAB adjustment for those costs incurred in RP5.

12 Financial Aspects

Detailed Approach – Utility Regulator Proposals

Overview

- 12.1 This chapter sets out the financial inputs into the Utility Regulator's price control calculations.

Rate of Return

- 12.2 The financial model provides for NIE to earn a return on its RABs. The value of this return is calculated as a weighted average of the costs of the equity and debt finance that NIE takes from investors.

- 12.3 In calculating the allowed cost of equity, the Utility Regulator, like most economic regulators, uses the Capital Asset Pricing Model (CAPM) to determine the returns that shareholders require in exchange for their equity investments. CAPM estimates the required return to be a function of the risk-free rate (R_f), the expected return on the market portfolio (R_m) and a firm-specific measure of risk (beta of β_e) as follows:

$$\text{Return on equity} = R_f + \beta_e \cdot (R_m - R_f)$$

- 12.4 In paragraphs 12.16 to 12.33 we explain how we have arrived at an estimate of the cost of equity.
- 12.5 The interest that NIE pays on its debts is directly observable, and in the first instance we propose to align the allowed cost of debt to the actual interest rates that NIE pays. However, NIE will need to refinance some of its existing debt during the RP6 period; it may also choose to raise new debt to finance new investment. These things mean that there is some uncertainty about the full interest costs that NIE will pay over the next six and a half years.
- 12.6 In assembling this draft determination, we have considered whether we should factor a fixed forecast of the company's financing costs into the RP6 allowed return. We note that there is an inevitable uncertainty about what these costs will be and that over- or under-estimating future interest payments will result in NIE earning excess returns or sub-normal returns for several years until the RP7 reset of price controls. Elsewhere in the UK's regulated industries, there have been criticisms of such 'windfall' gains and losses, with the likes of the National Audit Office and the UK government highlighting that it is unfair for regulation to be set up in such a way as to produce outcomes in which prices are likely to be significantly higher or significantly lower than they need to be in order to cover companies' actual costs of debt.
- 12.7 Against this background, we consider that it is in the best interests of both consumers and investors that we should provide for the allowed rate of return to adjust up or down in line with prevailing interest rates at the point(s) when NIE takes out new debt. NIE has indicated its support for this kind of approach.

- 12.8 We evaluated a number of possible designs for an adjustment mechanism during the recent GD17 review of gas distribution price controls. Our provisional view is that we should apply the final GD17 design to NIE, so as to align our approach across the sectors. In its submissions, NIE suggested a number of possible ways in which the GD17 mechanism could be improved. Our assessment at this stage is that it aids outsiders' understanding of the regulatory regime in Northern Ireland if we apply a common design across price controls. The proposed design is detailed in annex H.
- 12.9 We will need to hold further discussions with the company about the precise implementation of the adjustment mechanism prior to publishing our final determination. We will also need to set out our best current estimates of the costs of debt (i.e. the reference point for the sharing mechanism) in our decision. Our provisional estimate is set out in paragraphs 12.34 to 12.42.

Financeability

- 12.10 In carrying out its functions, the Utility Regulator is required to have regard to the need to secure that licence holders are able to finance their activities. Our assessment of financeability is set out in paragraphs 12.48 to 12.62.

Utility Regulator Proposals

Rate of Return

- 12.11 NIE made an initial submission on the RP6 rate of return in June 2016 and a further submission in February 2017. The figures put forward by the company are set out in **Table 55**.

Parameter	
Gearing	0.50
Cost of debt	2.6%
Risk-free rate	1.25%
Expected market return	6.5%
Asset beta	0.44
Debt beta	0.05
Equity beta	0.83
Post-tax cost of equity	5.6%
Vanilla cost of capital	4.1%

Table 55: NIE allowed rate of return submission

- 12.12 In evaluating this submission, and in considering the issues around the RP6 rate of return more generally, we have taken advice from the economic consultancy First Economics. The consultant's report is attached as Annex J to this paper.
- 12.13 Our draft determination is as follows.

Gearing

- 12.14 The weights that are accorded to equity and debt within the allowed rate of return calculation typically reflect a notional or efficient level of gearing. Other regulatory determinations for UK regulated utility networks have provided for gearing of between 45% and 65%. We propose to use a point estimate of 45% to be consistent with the 'exit rate' of gearing in the Competition Commission's 2014 modelling.
- 12.15 We note that the final WACC figure is not especially sensitive to gearing and we have also considered the issue of gearing levels in our financeability analysis.

Cost of equity

- 12.16 A calculation of the cost of equity capital can be formed by making estimates of the risk-free rate, the expected market return and beta. It is also important to consider the resulting cost of equity 'in the round'.

Risk-free rate

- 12.17 The return that investors demand in exchange for holding riskless assets is usually assessed by examining the yields on government gilts. At March 2017, real yields (after allowing for RPI-measured inflation) are negative, as has been the case for several years.
- 12.18 The emergence of below-inflation risk-free returns has come partly as a result of the recent financial crisis and policymakers' responses to subsequent recessions, including very low interest rates and programmes of quantitative easing. There is naturally some uncertainty about how long current market conditions will persist for.
- 12.19 Most UK regulators have been allowing for a positive RPI-stripped risk-free rate when setting forward-looking price controls. As set out in First Economics' report, figures used in recent decisions range from 0.5% to 1.5%. We propose to use a figure of 1.25% to be consistent with the estimate that the Competition & Markets Authority (CMA) used in its 2015 price control determination for Bristol Water. However, we also consider that this should be regarded as a figure that sits at the high-end of the range of current plausible values and that it may be appropriate to revisit this judgment prior to issuing our final determination.

Expected market return

- 12.20 The other generic or non-firm-specific parameter within the CAPM has also been considered at length in recent UK price reviews. The CMA, and its predecessor the Competition Commission (CC), have expressed the view that it is untenable to think of a real expected market return of more than 6.5%. The following excerpt is taken from the CC's 2014 report on NIE's price control:

"The interpretation of the evidence on market returns remains subject to considerable uncertainty. The CC said in recent regulatory inquiries that 7 per cent is an upper limit for the expected market return, based on the approximate historical average realized return for short holding periods. We think that it may be appropriate to move away from this upper limit based on historical realized returns and place greater reliance on ex ante estimates

derived from historical data which tend to support an upper limit of 6.5 per cent.”

- 12.21 Most UK regulators, with the exception of Ofwat, have factored the CC/CMA’s guidance on the 6.5% upper limit into the recent price control decisions. Given the clear steer from the CMA/CC on this matter, we are proposing a value of 6.5% in this draft determination. However, this is also an area in which we consider that further analysis may be helpful, in light of the low return external environment in which regulated utilities are operating, and we intend to discuss this matter further with our counterparts in the UK Regulators Network prior to making our final determination.

Beta

- 12.22 The betas of listed firms can be estimated empirically using stock market data. In this price review, however, we are concerned with a business that does not have a stock market listing. We have therefore sought to understand the betas that regulators have factored into other companies’ allowed rates of return and to position NIE logically against these comparators. The unit of comparison that we use is a firm’s assumed asset beta (a hypothetical measure of the beta that a firm would have at zero gearing).
- 12.23 The comparators are set out in Table 56. As a cross-check on these numbers, First Economics has also looked at empirical estimates of beta for the remaining listed network businesses in the UK. The calculations show that average asset betas over the last five years have typically been slightly below the figures in the table.⁷⁸

Regulator / company	Asset beta
Ofgem, gas distribution networks	0.38
Ofgem, electricity distribution networks	0.38
CC, NIE	0.40
Utility Regulator, PNGL and FE GD17	0.40
SGN, Gas to the West years 6-10	0.43 to 0.45

Table 56: Asset beta estimates

- 12.24 The key determinant of NIE’s positioning in the above spectrum is the risk that the firm presents to investors. We have therefore sought to understand how NIE’s risk profile compares to the other regulated networks.
- 12.25 In a number of respects, the networks are very similar. For example, most regulated companies nowadays (with SGN a notable exception) have revenues caps, like the revenue caps that we are proposing to put in place for NIE, which limit companies’ in-period exposure to unforeseen changes in volumes. There are also similarities across sectors between the overall strength of opex/capex/totex incentives and the amounts of money that are tied to output or service quality schemes across different price controls, even if the detailed design of such incentives differs from industry to industry.

⁷⁸ We consider that it is important to take a long run average so that our beta calculations are not unduly influenced by short term movements in share price data.

12.26 In the recent determination on GD17 we said

“Our chosen point estimate from this range is 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL’s and FE’s regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised above, the possibility that investors may not be wholly familiar with these differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing PNGL and FE at the top of the range that regulators have judged appropriate for low-risk network utility businesses.”

12.27 Ultimately, our analysis has not identified any intrinsic structural factor that distinguishes NIE in a material way from the GB electricity distribution networks. We also note that NIE has not suggested any such factor in its analysis.

12.28 NIE did, however, highlight that the Competition Commission in 2014 opted to position NIE’s asset beta slightly above the Ofgem betas when the Commission selected a point estimate of 0.40 from a stated 0.35 to 0.40 range. Its rationale for this positioning was that the GB comparators are “not an exact match for NIE and its regulatory framework”. Our assessment in 2017 is that such differences should not be overstated. Looking across this draft determination, and, indeed, back at the Competition Commission’s 2014 decision, there is clear read-across to Ofgem in our approach to many of the price control building blocks (e.g. length of control period, the design of totex sharing rules, the treatment of pension costs, and the insertion of a cost of debt adjustment mechanism). More fundamentally, absent any intrinsic structure differences in risk profiles, it is unclear why a sophisticated investor should consider the risks around NIE’s future equity returns to be materially different from the risks around GB DNO returns or why such an investor would require a higher return on equity.

Overall cost of equity

- 12.29 Table 57 shows how the overall calculation of the cost of equity would look if we were to combine our proposed figures for gearing, the risk-free rate and the expected market return together with an indicative asset beta of 0.38.
- 12.30 We also provide a comparison to other recent regulatory determinations. (NB: because these other determinations all provided for slightly different levels of gearing, we show in the final row of the table how the calculations would compare if all regulators were to have used a common 65% gearing ratio.)

Parameter	GB GDNs	NIE, RP5	GB electricity DNOs	FE and PNL, GD17	NIE, RP6
Risk-free rate	2.0%	1.5%	1.5%	1.25%	1.25%
Expected market return	7.25%	6.5%	6.5%	6.5%	6.5%
Asset beta	0.38	0.40	0.38	0.40	0.38
Cost of equity @ 45% gearing	-	5.0%	-	-	4.45%
Cost of equity at 55% gearing	-	-	-	5.3%	-
Cost of equity at 65% gearing	6.7%	6.3% *	6.0%	6.3% *	6.0% *

Note: an asterisk indicates a recalculated value. The figure for NIE is taken from table 13.13 of the CC inquiry report.

Table 57: Calculation and comparison of the allowed cost of equity

- 12.31 The table shows that the calculated cost of equity for NIE sits in line with the return that Ofgem gave to the GB electricity distribution networks in its most recent determination. It sits below the returns that Ofgem gave to the GB gas networks, reflecting moves forward in regulatory thinking on the generic inputs into CAPM since 2012. It also sits below the GD17 costs of equity given our decision in that review to give recognition to the unusual features of the GD17 price control framework.
- 12.32 We are content that this is a logical picture to present in this draft determination, especially in light of the ‘lower for longer’ market conditions that NIE appears to be operating in. That is to say that we do not think it would be appropriate for us to provide NIE with a return that exceeds any of the other benchmarks in table Our decision in this draft determination is therefore to provide in allowed revenues for a cost of equity of 4.45%.
- 12.33 As set out above, there may be reasons why allowing for a level of return that is commensurate with Ofgem’s 2014 RIIO-ED1 decision overstates the returns that NIE’s shareholders require in current low interest rate environment. We will consider this matter further prior to making our final determination.

Cost of debt

- 12.34 In line with the methodology set out in paragraphs 12.4 to 12.9, our provisional cost of debt is the current best estimate of the average interest rate that NIE will pay over the RP6 period, plus an allowance for transaction costs.
- 12.35 The calculations start with the interest that NIE will pay on its existing debt. NIE currently has two outstanding bonds: a £175m bond with a coupon of 6.875% that matures in September 2018; and a £400m bond with a coupon of 6.375% which matures in June 2026. This is equivalent to an average embedded debt cost of approximately 6.4% over the RP6 period. We add an annualised amount of 20 basis points to cover fees that the company incurred when entering into its borrowing arrangements, giving an all-in embedded cost of debt of 6.6%.
- 12.36 NIE has indicated that it intends to raise the new debt it requires for RP6 in one go at the end of 2018. We build up an estimate of the cost of this new debt as follows:⁷⁹
- first, we observe that the current yields on A and BBB rated debt in secondary markets are approximately 3.2-3.4%;
 - we allow for a small move up in interest rates of 0.45% by the end of 2018, consistent with forward gilt market rates; and
 - finally, we again allow for transaction costs of 20 basis points.
- 12.37 Table 58 brings these calculations together into an overall forecast of the nominal cost of debt. The 4:5 weights reflect the size of the RP6 borrowing requirement that NIE identified in its business plan, and may need to be revised prior to our final determination to align to our final projection of RP6 capital expenditure.

Company	Average nominal cost of debt, RP6			
NIE			Current market rates	3.3%
	Average interest costs	6.4%	Forward rate adjustment	0.45%
	Transaction costs	0.2%	Transaction costs	0.2%
	Embedded debt	6.6%	Cost of new debt	3.95%
			4:5 weighted average	
			Weighted average cost of debt = 5.1%	

Table 58: Cost of debt calculations

⁷⁹ These steps mirror the steps in the calculation that NIE put forward in its June 2016 submission. In February 2017 NIE belatedly then suggested that there should be a further component for an 'illiquidity premium'. We did not find NIE's evidence on this matter persuasive – e.g. it did not provide data to show how the yields on its existing bonds compare to the iBoxx indices – and we decided that it would be inappropriate to factor such a premium into this draft determination.

12.38 All of the above figures are best estimates at the cut-off date for First Economics' report, 31 January 2017 and will need to be updated prior to our final determination to reflect prevailing market conditions and to allow consideration of any further detail that emerges about NIE's financing plans.

12.39 We convert the nominal costs of debt in Table 59 into their real equivalents by adjusting for forecast RP6 inflation as projected by the Office for Budget Responsibility's in its latest published forecasts. This is consistent with the approach taken in previous reviews. The projected rate of inflation is 3.2% and the resulting real cost of debt is 1.87%. NIE suggested alternative inflation forecasts, but our view remains that the OBR forecasts are the most credible central estimate of future inflation.

12.40 Table 59 compares this figure to other recent regulatory decisions.

	GB GDNs, 2017/18	NIE, RP5	GB electricity DNOs, 2017/18	PNG and FE, GD17 starting values	NIE, RP6
Allowed cost of debt	2.22%	3.1%	2.29%	2.4%	1.87%

Table 59: Calculation and comparison of the allowed cost of debt

12.41 Our provisional estimate of NIE's cost of debt is lower than the other allowed costs of debt. This reflects the opportunity that NIE has to raise new debt at historically low rates of interest towards the start of the RP6 period, whereas other companies will have to go on servicing legacy debt at comparatively higher rate of interest for several more years.

12.42 It should also be noted that Ofgem's indexed costs of debt for the GB GDNs and electricity DNOs are likely to fall in the coming years. If we apply current debt market trends they would start to fall below 2% by as early as 2018/19 or 2019/20.

Overall rate of return

12.43 Table 60 combines our calculations of the cost of equity and the cost of debt into an overall rate of return for the RP6 period.

	NIE, RP6
Gearing	0.45
Pre-tax cost of equity	4.45%
Cost of debt	1.87%
Overall rate of return	3.29%

Table 60: Computed rates of return

12.44 Based on these calculations, we propose to factor a rate of return of 3.29% into NIE's price controls at the outset of the RP6 period.

12.45 Our starting rate of return is lower than the figure put forward by NIE (see **Table 55**) because we have:

- aligned NIE's return on equity to be no higher than Ofgem's estimated RIIO-ED1 cost of equity;
- updated NIE's February 2016 cost of debt calculation for the latest market evidence; and
- used the OBR's inflation forecast to translate the forecast nominal cost of debt into its real, RPI-stripped equivalent, in preference to NIE's lower inflation forecast.

12.46 As noted in paragraphs 12.5 and , the return may subsequently be adjusted up and down within period in light of any changes in market interest rates.

Peer Review

12.47 The Utility Regulator is a member of the UK Regulatory Network (UKRN) Cost of Capital working group. The purpose of the UKRN is to improve the level of co-ordination and consistency across the UK. It is our intention to have the WACC peer reviewed and this will provide useful feedback prior to the final determination.

Financeability

12.48 Article 14 of the Energy (Northern Ireland) Order 2003 requires us to carry out our functions in the manner we consider is best calculated to further our principal objective: having regard to the need to secure that licence holders are able to finance their licence obligations⁸⁰ (amongst other things).

12.49 This duty is framed similarly to the financing duties of other UK regulators and can broadly be taken to mean that the price control ought to be set at a level which would allow an efficient company to finance its licensed activities. It is therefore necessary for us to consider financeability as an integral part of a price review.

12.50 In assessing whether our draft determination leaves NIE in a position where it will be able to finance their activities during the RP6 period, we have considered the ability that the business will have to utilise both equity and debt finance.

12.51 The key determinant of the company's ability to access equity finance is the allowed return on equity. As noted in paragraphs 12.29 to 12.33, we have built returns by considering the level of returns that investors are likely to be able to get from other equity investments and by positioning the return offered by NIE logically against these alternative investments. Our proposed return is aligned to the return that Ofgem factored into its recent RIIO-ED1 price control calculations. Accordingly, we are satisfied that NIE ought to be capable of securing equity finance on an ongoing basis throughout the next control period.

12.52 As far as borrowing is concerned, it will be important for NIE to maintain investment-grade credit quality. One determinant of the business's credit worthiness in the eyes of lenders will be the level of cashflows that the networks generate under our price control proposals. A second key factor will be the amount of borrowing that the

⁸⁰ Activities which are the subject of obligations imposed by or under Part II of the Electricity (Northern Ireland) Order 1992 or the Energy (Northern Ireland) Order 2003.

company attempts to take on. We influence the first of these things, but the second is firmly in the hands of NIE's management and owner.

- 12.53 NIE has a licence condition to maintain an investment grade rating. An investment grade credit rating is a rating of BBB- or above (Fitch or Standard & Poor's) or Baa3 (Moody's). We are not prescriptive on which credit rating agency is used by NIE.
- 12.54 In Table 61 we present the results of some modelling that we have produced to understand the projected level of four financial ratios if NIE selects a gearing that is in line with the 45% figure that we use in our cost of capital calculations. These are the same metrics that the Competition Commission considered in its RP5 work, although we recognise there are other ratios that lenders and rating agencies consider.
- 12.55 The modelling incorporates costs and revenues based on the proposals in this paper.

	2017	2018	2019	2020	2021	2022	2023
PMICR	1.31	1.28	1.28	1.28	1.29	1.29	1.29
FFO interest cover	3.69	3.89	3.90	3.92	3.96	3.87	3.84
FFO to net debt	13.04%	13.33%	13.73%	14.21%	14.76%	14.62%	14.79%
Gearing	45%	45%	45%	45%	45%	45%	45%

Table 61: Modelling results

- 12.56 We have taken into account the considerations of the Competition Commission in its RP5 inquiry in thinking about appropriate threshold values for the above financial ratios. Our assessment is that adjusted interest cover ratio of at least 1.4 or more, FFO interest cover of 3.5 or more, FFO to net debt of 10% or more and gearing of no more than 70% will normally be consistent with a BBB+/Baa1 credit rating.
- 12.57 We also note that NIE view FFO interest cover to be the key measure of financial health. In its latest accounts to 31 December 2016 this ratio was 3.2 (3.1 for 2015) and was stated 'to be in line with the target level and confirms the Groups financial strength'.
- 12.58 The modelling shows that three of the four ratios are within threshold, the adjusted interest ratio is slightly below 1.4 times. This leaves some uncertainty about the rating that NIE will be able to achieve, in practice, on the back of RP6 cashflows if it selects a gearing of 45%. However, we note that financial ratios are one of several factors that rating agencies consider and is weighted at c40% in an overall decision.
- 12.59 In light of this uncertainty, we have also considered how NIE's ratios will look if it selects a more modest gearing ratio of, say, 40%. The results of this modelling exercise are shown below.

	2017	2018	2019	2020	2021	2022	2023
PMICR	1.39	1.44	1.44	1.45	1.45	1.45	1.45
FFO interest cover	3.89	4.38	4.39	4.41	4.45	4.35	4.32
FFO to net debt	14.76%	15.42%	15.93%	16.52%	17.20%	17.11%	17.36%
Gearing	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%

Table 62: Modelling results

- 12.60 The figures in Table 62 are more clearly compatible with a BBB+/Baa1 rating.
- 12.61 We have next considered the possibility that NIE might need to raise additional capital to finance D5 expenditure over and above the capex allowance factored initially into RP6 allowed revenues. This does not materially changes the analysis in either Table 61 or Table 62, assuming that NIE finances such expenditure using the same mix of equity and debt capital as it selects for the existing RABs.
- 12.62 Our assessment, therefore, is that NIE is capable of financing itself through the RP6 period with a prudent mix of equity and debt capital. We note that the calculated weighted average cost of capital at 40% gearing and 45% gearing would be identical (i.e. 3.29%), meaning that both the allowed rate of return and NIE's overall revenues need not be viewed as being dependent on any particular forecast on the Utility Regulator's part about NIE's future levels of borrowing.

Revenues, tariffs and customer impact

12.63 NIE Networks recovers its revenue through charges for the use of distribution system to electricity suppliers. Transmission charges are recovered from SONI.

RP6 REVENUE

12.64 NIE distribution revenue request for RP6 amounts to £1,284.3m in 2015/26 prices as shown in the Table 63.

Distribution Use of System (DUoS)	10/2017-03/2018	04/2018-03/2019	04/2019-03/2020	04/2020-03/2021	04/2021-03/2022	04/2022-03/2023	04/2023-03/2024	Total
Return	22.0	45.0	46.0	46.9	47.6	48.4	49.2	305.1
Depreciation	34.2	70.6	72.2	74.2	76.4	75.1	75.7	478.3
Tax	3.6	7.5	7.7	7.0	7.3	6.9	6.8	46.9
Opex	29.4	59.1	59.3	59.6	60.1	61.1	61.1	389.6
Pension	4.9	9.9	9.9	9.9	9.9	9.9	10.0	64.5
Total	94.2	192.0	195.0	197.5	201.3	201.4	202.8	1,284.3

Table 63: RP6 NIE distribution revenue request

12.65 Our proposals for distribution revenue for RP6 are shown in Table 64.

Distribution Use of System (DUoS)	10/2017-03/2018	04/2018-03/2019	04/2019-03/2020	04/2020-03/2021	04/2021-03/2022	04/2022-03/2023	04/2023-03/2024	Total
Return	17.6	35.7	36.2	36.5	36.8	37.0	37.3	237.0
Depreciation	35.2	69.7	70.9	72.3	73.8	71.0	70.1	463.1
Tax	3.7	7.8	7.7	6.8	6.8	6.1	5.7	44.6
Opex	26.5	52.3	52.0	51.7	51.4	51.2	51.0	336.1
Pension	5.0	10.0	10.0	10.0	10.0	10.0	10.1	65.0
Total	88.0	175.5	176.8	177.3	178.8	175.3	174.2	1,145.8

Table 64: RP6 Utility Regulator proposals for distribution revenue

- 12.66 NIE transmission revenue request for RP6 (excluding transmission network reinforcement projects expenditure of £200m) amounts to £278.2m, as shown in the Table 65.

Transmission Use of System (TUoS)	10/2017-03/2018	04/2018-03/2019	04/2019-03/2020	04/2020-03/2021	04/2021-03/2022	04/2022-03/2023	04/2023-03/2024	Total
Return	6.6	13.7	14.0	14.3	14.5	14.7	14.7	92.4
Depreciation	7.7	16.0	16.4	16.8	17.2	17.6	17.8	109.5
Tax	0.5	1.3	1.4	1.2	1.3	1.4	1.6	8.8
Opex	3.6	7.3	7.3	7.3	7.4	7.4	7.5	47.9
Pension	1.5	3.0	3.0	3.0	3.0	3.0	2.9	19.5
Total	20.0	41.4	42.1	42.7	43.5	44.1	44.5	278.2

Table 65: RP6 NIE transmission revenue request (excluding transmission network reinforcement projects expenditure of £200m)

- 12.67 Our proposals for transmission revenue for RP6 (transmission network reinforcement projects expenditure of £200m) are also shown in Table 66.

Transmission Use of System (TUoS)	10/2017-03/2018	04/2018-03/2019	04/2019-03/2020	04/2020-03/2021	04/2021-03/2022	04/2022-03/2023	04/2023-03/2024	Total
Return	5.4	10.8	11.0	11.3	11.5	11.5	11.4	72.9
Depreciation	7.7	15.3	15.7	16.2	16.6	16.9	17.0	105.4
Tax	0.7	1.4	1.3	1.1	1.1	1.1	1.3	7.9
Opex	3.3	6.6	6.5	6.5	6.5	6.4	6.4	42.1
Pension	1.5	3.1	3.1	3.1	3.1	3.0	3.0	19.8
Total	18.6	37.1	37.6	38.1	38.7	39.0	39.0	248.1

Table 66: RP6 Utility Regulator proposals for transmission revenue (excluding transmission network reinforcement projects expenditure of £200m)

RP6 Tariffs and Consumer Impact

- 12.68 In 2015/16 total network charges accounted for approximately 21% of the final electricity bill. This percentage varies each year depending on the electricity wholesale prices and other costs which make up the final bill such as system operator costs and supplier costs.
- 12.69 The percentage of the final electricity bill also varies depending on the customer group. Network charges account for approximately 25% of the final bill for domestic and 22% for small business customers. For large energy users and small to medium enterprise customers, network charges account for between 5% and 18% of the final electricity bill.

12.70 The annual increase in customers' bills is summarised in Table 67.

Customer group	NIE proposed Average annual increase in network charges (2016/17 to 2023/24)		Utility Regulator proposed Average annual increase in network charges (2016/17 to 2023/24)	
	Increase in network charges, £/annum	Increase in retail bill, %/annum	Increase in network charges, £/annum	Increase in retail bill, %/annum
Domestic	1.5	0.28	(1.3)	(0.25)
Small business	7	0.25	(6.0)	(0.22)
SME > 70k VA	109	0.21	(93.9)	(0.18)
LV & HV LEU > 1MW	855	0.12	(660.3)	(0.10)
33kV LEU >1 MW	2,293	0.07	(1,393.8)	(0.04)

Table 67: NIE's average annual increase in customers' bills compared to Utility Regulator's proposed average annual decrease in customers' bills.

12.71 Table 68 shows a comparison of NIE's proposed average network charges at the end of RP6 (2023/24) compared to the Utility Regulator's proposed average network charges at the end of RP6 (2023/24)

Customer group	Number of customers	NIE proposed Average network charges at the end of RP6			UR proposed Average network charges at the end of RP6		
		D £/annum	T £/annum	Total £/annum	D £/annum	T £/annum	Total £/annum
Domestic	790,000	123	17	140	106	15	121
Small business	65,000	579	83	662	498	73	571
SME > 70k VA	5,000	8,807	1,485	10,292	7,570	1,303	8,873
LV & HV LEU > 1MW	172	58,358	19,667	78,025	50,158	17,257	67,415
33kV LEU >1 MW	18	103,902	91,441	195,343	89,302	80,236	169,538

Table 68: RP6 NIE Transmission and Distribution forecast average network charges

12.72 In summary, our proposals would result in a small decrease over the six years of RP6 on the network charges paid by consumers. It is important to remember that these figures all exclude RPI inflation, which is applied to NIE Transmission and Distribution allowed revenue each year.

12.73 The NIE Networks business plan excluded costs associated with potential load related projects which are uncertain and have not yet been approved. These project are referred to as transmission network reinforcement projects and are explained in more detail in paragraph 9.28.

12.74 Given it likely many of these projects will proceed we regard it as appropriate to model this impact and have included £200m of additional network investment in RP6. These projects will deliver benefits which significantly outweigh the impact on network tariffs but we only set out here the impact on network tariffs. The results of this comparison are shown in Table 69 and Table 70.

Customer group	End of RP5	End of RP6		
	Current	NIE Networks (excl additional investment)	Utility Regulator draft determination (excl additional investment)	Utility Regulator draft determination (incl additional investment)
Domestic	130	140	121	126
Small business	613	662	571	595
SME > 70k VA	9,530	10,292	8,873	9,292
LV & HV LEU > 1MW	72,037	78,025	67,415	72,960
33kV LEU >1 MW	179,295	195,343	169,538	195,320

Table 69: RP6 effect on NIE network charges with the inclusion of the transmission network reinforcement projects work

	NIE Networks (excl D5) £m	Utility Regulator draft determination (excl additional investment) £m	Utility Regulator draft determination (incl additional investment) £m
Distribution	1,284.3	1,145.8	1,145.8
Transmission	278.2	248.1	294.8
Total	1,562.5	1,393.9	1,440.5

Table 70: RP6 effect on NIE Networks revenue with the inclusion of the transmission network reinforcement projects work

12.75 The effect of the draft determination is to reduce revenue and network charges when compared to the RP6 Business Plan submission on both the model runs presented ie excluding and including the additional expenditure.

13 RP6 Uncertainty Mechanisms

Introduction

- 13.1 All price controls need to set out clearly under what circumstances, if any, the figures set in the final determination can change. We refer to this generally as the Uncertainty Mechanism.
- 13.2 Our proposed RP6 uncertainty mechanisms have been built upon both the Competition Commissions determination of RP5 and our experience in developing the RP5 Licence Modifications.
- 13.3 We have set out below how different areas of the price control might be adjusted as part of the RP6 process. This ranges from:
- some costs which are pass through so determined allowances will be adjusted to reflect actual costs;
 - ring fenced items which will require a further regulatory approval before it becomes a formal part of the RP6 allowances;
 - pass-through of unit costs subject to volume drivers; and
 - substitution mechanisms subject to a limit on the value of outputs which can be substituted out of any single allowance to support emerging pressures in other areas of the capital programme, for example.
- 13.4 Where we are of the view that certain RP5 uncertainty mechanisms ought to be retained we state as such, making references to how the RP5 mechanisms might be developed further to meet the need for transparency, providing the right balance between giving the company risk mitigation and protecting the consumer.
- 13.5 We plan to continue our work on this area as we work towards the final determination in order to provide adequate detail so there is clarity on how the mechanisms will work.

Licence fees

- 13.6 The Utility Regulator's licence fees are calculated each year and allocated across licence holders. The company assumed fees would remain at the same level as those incurred in 2015/16 across RP6 and allocated between distribution and transmission on the basis of headcount.
- 13.7 The company seeks a pass through of the Utility Regulator's licence fees and we are minded to continue the previous RP5 licence mechanism regarding such costs.

Direct network investment allowance substitution

- 13.8 In its business plan submission, NIE Networks highlighted the uncertainty inherent in estimating planned volumes of network investment in RP6 which will run until 31 March 2024. Over this period, it is likely that changes in the rate of deterioration of different types of assets will change and the rate and/or extent which assets will require refurbishment or replacement will vary, either up or down.
- 13.9 To deal with this uncertainty, the company proposed that the Utility Regulator introduce a new mechanism in RP6 which will allow it to substitute higher priority outputs for lower priority outputs which are then deferred to a future price control without a financial penalty to NIE Networks. In its business plan submission, the company proposed a cap on substitutions equal to 15% of the overall RP6 asset replacement programme (excluding rolling programmes).
- 13.10 In a recent update to its proposals the company suggested that it should be free to undertake whatever substitution it thought fit against the planned outputs to allow it to deliver the correct asset management intervention in response to new information.
- 13.11 A similar substitution mechanism for network investment was proposed by the company for the RP5 price control. This was considered by the Competition Commission which concluded that there was sufficient flexibility in the planned network investment to allow the company to deliver its obligations without a substitution mechanism. Part of this flexibility is the opportunity to substitute outputs within any allowance but not between allowances.
- 13.12 Throughout RP5, NIE Networks has highlighted a concern that, in the absence of a substitution mechanism:
- i) the Utility Regulator would conclude that any shortfall in output volume delivered in RP5 was deferral of investment which would be treated as a pre-funded cost for RP6; but,
 - ii) the delivery of any volume of output in excess of the planned investment or investment to address any emerging pressure would be funded by the company from its own resources or from out-performance in other areas.
- 13.13 From our assessment of the current and forecast information on the delivery of network investment and outputs in RP5 it appears that the company has generally stuck to the planned network investment outputs for each allowance. While the company has applied substitution within individual allowances, it has not generally carried out additional work over and above that envisaged in the planned network investment for RP5.
- 13.14 We understand the point made by the company and believe that additional flexibility is necessary to allow it to respond to changes in priorities and emerging pressures by substituting one type of work for another without either suffering a financial penalty or requiring a separate decision from the Utility Regulator to do so. However, this must be balanced by:

- i) a need to maintain an incentive on the company to prepare a robust plan for network investment at each price control; and,
- ii) a need to ensure that consumers are not disadvantaged by a high degree of change between planned and actual delivery of network investment which complicates a future assessment of pre-funded costs.

13.15 In view of this, we have concluded that an open ended substitution mechanism for network investment is not in the interests of consumers in the long term. However, we have concluded that the company should have some flexibility to substitute investment between allowances to deal with changing priorities and emerging pressures subject to reasonable safeguards on the assessment of deferral pre-funded costs to protect the interest of consumers.

13.16 This mechanism would apply only to substitution between allowances for which an activity volume has been defined in Annex P

13.17 We propose to set a limit of 20% on the value of outputs which can be substituted out of any single allowance to support emerging pressures in another area. Over a 6.5 year price control this is equivalent 1.3 years worth of planned outputs at a constant run rate. The fact that much of the planned investment consists of the on-going refurbishment and replacement of assets and continues from price control to price control provides a sound basis for planned volumes in the investment plan. Any sustained reduction in delivery against planned volumes is therefore likely to lead to an increase in the volume necessary in a subsequent price control and increase risk to consumers in the meantime.

13.18 We are conscious of the views expressed by the Competition Commission in respect of a substitution mechanism in its final determination in RP5. We note the risk that any substitution mechanism could be a source of complexity that limits our ability to assess the outcome of a price control period effectively and make a robust assessment of any potential double funding of outputs across price controls. Limiting the extent of substitution is one way of addressing this risk. In addition, we will assess whether substitution has been undertaken on a fair value basis and we will consider the impact of substitution on the revealed unit costs and volumes when we assess deferral and determine pre-funded costs for the subsequent price control. We have set out general principles in Section 14 which will inform this assessment.

13.19 We will consider responses to this consultation and take this into account in designing further detail on the mechanism in the final determination.

D5 – Investment projects to increase transmission capacity

13.20 For RP5, the Competition Commission made provision for the UR to adjust NIE's maximum revenue and RAB, during the price control period, to allow for additional investment projects to increase the capacity and capabilities of NIE's transmission system.

- 13.21 In its business plan submission, NIE Networks proposed that this mechanism continues during RP6.
- 13.22 We propose to continue this mechanism in RP6 for projects required to increase the capacity and capability of the transmission network.
- 13.23 While this mechanism was established for projects to increase the capacity or capability of the network, it will also to be applied to other defined projects where there is material uncertainty about the scope and cost of work. These projects are identified in paragraph 9.26.
- 13.24 It may also be necessary to consider the impact of Business Rates associated with such projects as part of this mechanism. As noted in paragraph 6.60, this is not a straight forward issue and we will give further thought to whether it would be appropriate to include this within the D5 mechanism in the final determination.

Changes to Transmission protection philosophy

- 13.25 In its business plan NIE Networks noted that SONI is in consultation with NIE Networks on a revision to the current transmission protection philosophy. The company asked that we include a reopener mechanism in RP6 to allow additional funding if any changes result works beyond that which are funded under the RP6 determination.
- 13.26 We have concluded that any such changes in the requirements placed on NIE Networks can be determined under the D5 mechanism whose scope includes changes to improve the capability of the transmission system.
- 13.27 NIE Networks has noted that SONI will be required to provide the business case for any enhanced works beyond those already planned by NIE Networks and funded under the RP6 price control. We expect the company to review this business case in the broader interest of its consumers during its consultations with SONI. We will consider the business case and NIE Networks D5 submission on completion of this consultation.

Connections charge pass-through

Introduction

- 13.28 This sub-section discusses whether the connections charge pass-through of capex and opex costs should be removed for all types of new or modified distribution and transmission connection.
- 13.29 Customers seeking a new or modified connection currently pay connections charges (or 'customer contributions') based on the estimated cost of the connection work. After the customer has been charged, NIE Networks will then carry out the work and so incur the actual cost (or 'expenditure').

13.30 The difference between customer contribution and expenditure on capex and opex for distribution and transmission connection work is currently passed-through to the RAB (on a yearly basis as a deduction or an addition). We refer to this as the connections charge pass-through.

RP5 background

13.31 The CC set out that the capex costs for the following types of connection⁸¹ should be pass-through in its FD:

- New Domestic and smaller business/ legacy subsidy: Utility Regulator removed a 40% subsidy of connection costs recovered from the RAB, which was to be phased out from 1 October 2012.
- Housing sites with 12 or more dwellings: NIE Networks currently builds connection infrastructure for these and then charges once the dwellings become occupied. The connection charges are via structured on a standard basis (average cost of connections for all completed developments in the preceding year).
- Cluster: Where multiple generators seek new connections close to each other using shared infrastructure.

13.32 In our September 2015 consultation, on the proposed licence modifications to implement the CC's RP5 decisions,⁸² we explained that the CC had not explicitly considered other types of connection (for example, renewable generation) in its FD.

13.33 We, therefore, considered that other types of connection (as referred to in paragraph 9.8 above) should remain pass-through in RP5, as had been the case in RP4. However, we also signalled that we would revisit the policy in RP6 in light of a further review of the connections policy and introduction of contestability.

13.34 In our second (November 2016) Consultation, we proposed that the pass-through for capex and opex costs, associated with all types of connection, should be reflected in changes to NIEs Distribution and Transmission Licences (under Article 14).⁸³

Recent developments

13.35 NIE Networks and SONI have since introduced contestability for customers seeking a connection of more than 5MW capacity. NIE Networks plan to introduce contestability for those remaining customers seeking a connection of less than 5MW by March 2018.

13.36 We commenced our connections policy review and issued a call for evidence in November 2016.⁸⁴ As part of this we asked whether the level of pricing transparency

⁸¹Each of which are addressed at paragraphs 10.227, 10.301 and 10.335 in the FD text:

https://assets.digital.cabinetoffice.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

⁸²https://www.uregni.gov.uk/sites/uregni/files/consultations/2015_09_22_Consultation_on_NIE_Networks_Licence_Mods_combined_version.pdf

⁸³The pass-through is currently not defined in NIEs licence covering RP4. We have consulted on modifications to the NIE Licence to formalise the outcome of the CC's RP5 final determination:

<https://www.uregni.gov.uk/consultations/consultation-nie-networks-licence-modification-transmission-and-distribution-rp5>. Schedule 8 & 9 define and set out the proposed modifications to the connections pass-through.

for connections charging should be strengthened. We will very shortly set out our next steps on whether connections pricing transparency should be strengthened further as part of our forthcoming publication on connections policy.

RP5 and RP6 pass-through costs (2015/16 prices)

- 13.37 In RP5 years 2012/13 to September 2017 total expenditure on all connections is c£10m greater than total customer contributions for distribution and transmission connections. NIE Networks has explained that the main reason behind this is that there are timing differences between the receipt of monies from customers and actual costs being incurred. We would expect that these costs and revenues balance out over time.
- 13.38 During RP6, total expenditure is forecast to be c£2m greater than total customer contributions during this period.

Our provisional view on connections pass-through

- 13.39 The following points support removing the new connections pass-through capex and opex costs for all types of distribution and transmission connection:
- First, removing the pass-through gives NIE Networks better incentives to minimise the connection costs. The costs and activities are largely within NIE Networks control. Exposing it to the full risk of recovery is likely to better incentivise NIE Networks to be more efficient in the provision of connections than the status quo.
 - Second, we note that costs and activities are caused by connecting customers. Removing the pass-through and recovering the costs from the customer seeking the connection is likely to, on balance, support better effective price signals to connecting customers compared with the status quo.
 - Third, removing the pass-through is more likely to support contestability. Where contestability is likely to be effective, there is a risk that a pass-through encourages NIE Networks to under-estimate connection charges.⁸⁵
- 13.40 Removing the pass-through for 'Housing sites with 12 or more Domestic Premises' type connections would also remove standard connection charges for these connections. Connection charges for these services could instead be made on an individual, up-front basis.
- 13.41 On the one hand, removing the pass-through for 'Housing sites with 12 or more Domestic Premises' type connections would allow NIE Networks flexibility to set prices in a more cost-reflective way for these types of connection. This may further support the aims of contestability by promoting a level playing field in pricing for connections. However, on the other hand, we understand that some developers may want the existing standard charging structure to continue, as they benefit from the certainty which the structure brings.

⁸⁴ <https://www.uregni.gov.uk/publication/electricity-connections-call-evidence-november-2016>

⁸⁵ NIE Networks has the ability and incentive to recover any shortfalls in contributions being made from the RAB.

Proposals

- 13.42 Given the balance of views with respect to 'Housing sites with 12 or more sites', we have set out two options regarding the pass-through for opex and capex distribution and transmission costs:
- Option 1: Retain the pass-through for 'Housing sites with 12 or more sites', but remove it for all other types of connections (this would not in itself lead to a change in the current connection charging structure).
 - Option 2: Remove the pass-through for all types of connection (this would lead to a more cost reflective connections charging structure for 'Housing sites with 12 or more sites' connections).
- 13.43 On balance, we are minded to remove the pass-through for all types of connection (Option 2), but we welcome views and evidence to the contrary.
- 13.44 If we were to remove the pass-through for 'Housing sites with 12 or more sites' then any consequential change in the connections charging methodology would require public consultation and be subject to our approval. We would expect the new connections charging methodology to be introduced at the same time as RP6 begins.

Recovery of outstanding expenditure and income

- 13.45 The removal of the pass-through would take effect from the date on which RP6 is introduced in October 2017. Any changes to connection charges from removal of pass-through for 12 housing sites would also take effect at this point.
- 13.46 We welcome evidence from NIE Networks as to whether introducing these changes means there is an impact on over or under recovery which necessitates an adjustment to the opening RP6 RAB, and over what period this will occur. Our initial view is that we would expect the completion of the over and/or under recovery by 1 October 2019.

Clusters

- 13.47 NIE Networks "clusters" generation connections together so that they will share network infrastructure. The purpose is to reduce the number and length of new overhead lines needed for the connections and lessen the environmental and visual impact of connections infrastructure build.
- 13.48 NIE Networks has sought approval from us to build clusters on a project by project basis during RP5. It has said that it has spent just under £31m and received £32.5m in contributions towards these costs during RP5.⁸⁶
- 13.49 The company requests that this mechanism continues during RP6. In doing so it notes that the closure of the Northern Ireland Renewable Obligation (NIRO),

⁸⁶ NIE Networks RIGs reporting, received by Utility Regulator February 2017.

contestability, changes to connection application procedure and less available network capacity may affect demand for clusters.⁸⁷

- 13.50 We note NIE Networks reasoning. We agree with its proposal that it will not incur any expenditure in relation to new cluster developments without the Utility Regulator's approval on a project by project basis.
- 13.51 We also expect to publish our next steps on connections policy very shortly. We will set our view in this document on whether the methodology for clusters, as set out in the connections charging statement, should remain.

Public Realm and large scale road schemes

- 13.52 In its business plan submission NIE Networks proposed that an additional mechanism should be included in the RP6 price control to adjust the maximum revenue and RAB to cover unpredictable but potentially large public realm schemes and NIRAUC⁸⁸ road schemes. NIE Networks initially proposed that this should apply to schemes which required contributions from the company of greater than £100k but amended this threshold to £500k during subsequent engagement. In its submissions and in discussion, the company has highlighted major schemes which might be implemented in the RP6 period.
- 13.53 We recognise that individual road schemes could require large contributions from NIE Networks. However, we have based our assessment of investment in RP6 on historical run-rates of investment. NIE Networks has provided us with information on completed and current public realm schemes which suggests that historical investment includes individual schemes up to £0.5m.
- 13.54 In addition, we note that public realm work and major road schemes are funded by the NI Executive. Major schemes must compete for funding with each other and within the overall Executive budget. In the current economic climate, there are on-going pressures on government investment and there is no indication of any general increase in investment in roads compared to recent years. While there may be some large individual schemes in the future, this may be at the expense of smaller schemes.
- 13.55 In view of this, our draft determination is that it is not appropriate to establish a new mechanism to address changes in requirements for public realm or major road schemes which is one of many risks and opportunities within the planned network investment programme.

⁸⁷ NIE Networks Business plan submission to Utility Regulator, Page 441.

⁸⁸ NI Road Authority and Utility Committees

Metering

- 13.56 As per the metering section, the approach taken for the RP6 metering programmes continues with a volume driven allowance and a set unit cost for each type of meter installation as adopted in RP5. This has been applied to all metering programmes in RP6.
- 13.57 The forecast figures are corrected with the actual volumes when the number of installed meters is known.

I-SEM

- 13.58 New wholesale electricity market arrangements are currently being designed to replace the existing Single Electricity Market (SEM), which applies across the island of Ireland. The introduction of I-SEM is a requirement arising from changes to European legislation designed to harmonise cross border trading arrangements across all European electricity markets. The I-SEM market will take effect from 2018.
- 13.59 The company contend changes to any of its market operations systems and processes would be outside NIE Networks' control. As such, the company proposes any costs they incur with the development of I-SEM or other market developments during RP6 should be allowed through the price control.
- 13.60 The company further states it is difficult at the present time, indeed even as far forward as the final determination 28 June 2017, to pinpoint whether new requirements might emerge after the "go live" date. If any new requirements emerge NIE Networks states it shall seek further funding during the RP6 period.
- 13.61 For the purposes of benchmarking, either in the run up to RP7 as we produce annual cost and performance reports on NIE Networks or to inform the RP7 price control, the Utility Regulator would be minded to consider any approach by the company around the RP7 price control, to treat I-SEM costs as possible atypical costs for the purposes of efficiency benchmarking.
- 13.62 We are minded to continue the previous RP5 licence mechanisms regarding uncertainties and would consider the current change of law provision as providing adequate risk mitigation for the company and consumers.

Costs associated with injurious affection

- 13.63 In the RP5 draft decision the Utility Regulator noted that the costs associated with injurious affection were uncertain due to the pending outcome of the Lands Tribunal determination. In the final determination by the CMA for RP5 they considered possible approaches to deal with efficiency, cost recovery and incentivising NIE Networks.
- 13.64 The CMA landed on a solution such that there will be no upfront allowance for costs relating to injurious affection, but a provision for the Utility Regulator to make an

allowance in the future following the Lands Tribunal determination. They also stated that we should consider giving weight to data from GB DNOs and also take account of any differences between the Lands Tribunal determination and relevant precedent from GB.

- 13.65 The CMA made a provision in the price control formulae for an opex allowance and RAB additions for licence modifications in respect of injurious affections claims in RP5.
- 13.66 As far as injurious affection is concerned for RP6 there is no change in circumstances from the time of the CMA determination, in that we still await the outcome of the Lands Tribunal. Thus uncertainty continues and the rationale adopted by the CMA remains the same. We therefore propose to adopt the same approach in RP6.
- 13.67 There will be no upfront allowance for costs relating to injurious affection but a provision to amend the revenue control on NIE Networks to include an upfront allowance. We will determine an allowance in light of submissions from NIE Networks and consultation with stakeholders once the Lands Tribunals decisions are known.
- 13.68 The existing licence modifications from RP5 providing for opex allowance and RAB additions will remain with a provision for any necessary licence changes to be made dependent on the final approach to be adopted.

Wayleaves

- 13.69 In its business plan submission, the company proposed a new uncertainty mechanism which would make provision for the UR to adjust NIE's maximum revenue and RAB during the price control period, to allow changes in the cost paid for wayleaves if these change by more than 10% in RP6 for reasons outside NIE Network's control.
- 13.70 We note that wayleave costs form part of the indirect costs which have been determined by benchmarking with GB DNOs. We are not aware of a mechanism for varying the maximum revenue or RAB of GB DNO's in response to changes in wayleave costs.
- 13.71 Wayleave costs are one item of a general basket of indirect costs for which no specific outputs or output volumes have been specified. The company has the ability to manage the future opportunities and risks inherent in this broad basket of works. In view of this we do not consider it appropriate provide a specific mechanism to mitigate the risk of increase costs in one particular element within the overall basket of works. In this respect, the company bears the same level of risk as GB DNO's and this is reflected in the return on capital.

Corporation Tax

13.72 We do not propose making any changes to the applicable tax rate used within the calculation of NIE revenues. For clarity this means it will continue to be the rate applicable in Northern Ireland as specified from time to time by HMRC.

Change of Law

13.73 We do not propose making any amendments to the change of law provisions during RP6.

GSS

13.74 GSS is included in the base costs within RP6 which are benchmarked against GB DNOs, who are already implementing the Electricity (Standards of Performance) Regulations 2015. Therefore we do not propose to introduce any uncertainty mechanism in relation to GSS (GSS is discussed further from paragraph 4.19.).

Load re-openers

13.75 In its final determination for RP5, the Competition Commission set an ex-ante allowance for load related investment, subject to the 50/50 cost risk sharing mechanism only.

13.76 In its RP6 submission, NIE Networks proposed that an ex-ante allowance be set for load related investment subject to a reopener mechanism at the mid point of the price control period to manage uncertainty in the estimates. The re-opener would be triggered if the planned expenditure in RP6 was expected to be 20% less or 20% more than the ex-ante allowance. The company noted that this approach is similar to the approach adopted by Ofgem to manage load related investment uncertainty for GB DNO's.

13.77 Load related investment has three major components:

- i) On-going increase in demand from new connections or changing consumption from existing consumers.
- ii) Investment to address 'congestion' on the 33kV network to facilitate distributed generation connections.
- iii) Potential for increasing load from 'low carbon technologies' such as electric vehicle recharging or heat pumps which displace carbon based fuels at the expense of increasing electricity demand.

13.78 In our opinion the key uncertainty in this bundle of investment is the rate of uptake of low carbon technologies and the impact on peak loads. In our view, it is reasonable to set an ex-ante allowance for on-going demand from new connections or changing

consumption from existing consumers based on the long term growth projections and the company's technical assessment of need. We recognise that there has been a short term peak in the demand for new distributed generation connections driven by subsidies to promote wind and solar power. However, these subsidies have reduced in recent years and the company has been able to consider the demand for generation connections in its business plan. Therefore we consider it reasonable to set an ex-ante allowance for 33kV 'congestion' in the draft determination. The key risk remains the impact which the uptake of low carbon technology will have.

- 13.79 For the business plan submission, the company adopted the TRANSFORM model to predict the impact of low carbon technology uptake on the load related investment. While it is not asset specific, this model aims to represent the types of circuits and current loading of NIE Networks distribution network. It makes assumptions about low carbon technology up-take – a low uptake assumption was used to formulate the business plan. It then estimates how low carbon technology will impact peak loads on the networks including assumptions about how uptake will be clustered and peak unit loads and diversity of peak load (for example how consumers will chose to charge electric vehicles). Using this approach, the company estimated the load growth investment driven by low carbon technology in RP6 would be £13.1m of which £6.0m would occur in the last three years.
- 13.80 Because the impact of low carbon technology is uncertain and the impact is expected to accelerate over RP6, we have proposed that investment driven by low carbon technology should be subject to a reopener at the mid-point of RP6 as follows:
- i) The draft determination includes an ex-ante allowance for low carbon technology load growth of £2.6m.
 - ii) The draft determination includes an additional ring fenced allowance of £10.5m for low carbon technology load growth. This will be replaced by an ex-ante allowance to be determined on the basis of assessment of low carbon technology load growth at the midpoint of RP6.
 - iii) The company shall make a submission setting out its assessment of low carbon technology uptake for the last three years of RP6 by the 1st September 2020. This should include:
 - (i) A statement of the profile of low carbon technology uptake to date.
 - (ii) An estimate of the impact this has had on peak network load and the investment that NIE Networks has had to make to address this.
 - (iii) A forecast of the uptake of low carbon technologies over the last three years of RP6, setting out the basis for that forecast.
 - (iv) Its latest best estimate of the impact of forecast low carbon technology uptake on peak loads and an estimate of the additional investment required to address this increase including all supporting calculations.

- 13.81 We will review the company's forecasts and estimates and make a preliminary determination of an ex-ante allowance by the 15 December 2020 and make a final determination by the 1 March 2021.

Design of Uncertainty spreadsheet

- 13.82 We envisage the requirement for an uncertainty mechanism spreadsheet during RP6. This will keep detailed calculations relating to some uncertainties outside the core formula as specified in the licence.
- 13.83 This may also mean the licence formula can be less complex in future and is something which we intend to expand further in advance of RP7.

Calculation of RP6 opening values

- 13.84 RP6 opening values should naturally be the closing values from the RP5 price control, and adjusted where necessary to 2016 prices. However at the time the RP6 licence modifications will be published for consultation the RP5 closing values will not be known due to the period being incomplete.
- 13.85 This means it will not possible to hard code opening values into the RP6 licence and we will need to consider how this can be implemented. We do intend to publish a RP5 model with the latest actuals and forecast figures assumed in preparing the RP6 determination. This will ensure transparency is maintained in arriving at the opening values.

14 RP6 Incentive Mechanisms

Introduction

- 14.1 The Utility Regulator applies both financial and reputational incentives to the monopoly network utilities it regulates by price controls. This ensures that companies can expect to be called to account over their delivery of investment, service levels and efficiencies, both in financial terms and RP6 outcomes, outputs and KPIs.
- 14.2 The following incentives formed the basis of the RP5 regulatory framework:
- underspending capex and opex allowances;
 - reducing electricity theft;
 - avoiding inefficient spending; and
 - guaranteed standards
- 14.3 Our RP6 Approach Document identified the following (non-exhaustive) list of financial incentives which could potentially be introduced in RP6:
- the electricity losses incentive;
 - quality of supply incentive e.g. frequently measured as customer interruptions (CI) or customer minutes lost (CML);
 - asset health or load indices incentive;
 - customer service incentive;
 - worst served customers incentive;
 - reducing carbon from network operation incentive; and
 - timely delivery of major projects incentive.
- 14.4 The company stepped up to the challenge of identifying its own long list of potential incentive mechanisms for RP6, including the above items, and discussed the pros and cons of each, prior to submitting its proposals.
- 14.5 As stated in our RP6 Approach Document, reputational incentives remain largely supported by our intended publication of NIE Networks' progress against RP6 targeted outcomes / outputs and KPIs as included within the RP6 Monitoring Plan. The annual Cost and Performance Report of NIE Networks will form part of our normal monitoring and enforcement activity.
- 14.6 The following sub-sections to this chapter detail our considered views on the company's proposals alongside our own draft determination proposals for consultation feedback.

50:50

- 14.7 The CC for RP5 determined that a cost- risk sharing mechanism under which certain cost categories could be subject to a 50/50 sharing mechanism and any over/under recovery in a particular financial year from set price control allowances could be shared 50/50 between the company and consumers⁸⁹.
- 14.8 We are not proposing to amend this precedent set by the CC and consider it appropriate to use this mechanism for relevant adjustments in RP6. There is already a licence mechanism in place for the operation of this 50/50 sharing mechanism and we are minded to retain this for RP6.

Inefficient spend clause

- 14.9 The RP5 price control introduced a provision which enables the UR to make adjustments to the price control to protect customers from exposure to any cost that are found to be demonstrably inefficient or wasteful.
- 14.10 We do not proposing to amend this approach during RP6.

Measures to tackle risks from deferral of planned network investment projects

- 14.11 In its final determination for RP5, the Competition Commission established a D3 mechanism – measures to tackle risks from the deferral of planned network investment.
- 14.12 In its business plan submission NIE Networks supported retaining this mechanism during RP6 as part of a suite of uncertainty and incentive mechanisms.
- 14.13 We have concluded that the RP5 D3 mechanism should continue to apply during RP6.
- 14.14 For RP6, we have concluded that it is necessary to provide additional flexibility to allow the company to substitute investment and outputs between allowances to address changes in priorities and emerging pressures during the course of the price control. This is described in Section 14 from paragraph 14.5.
- 14.15 In the following sub-paragraphs we note some of the key characteristics of the mechanism:
- i) The intention is to incentivise NIE Networks to make economic deferral of investment yet protect consumers from the paying for the same investment in a subsequent price control (a policy of no double funding of deferred investment).

⁸⁹ Refer to the CC Final Determination on RP5 https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf).

- ii) This is achieved in practice through a clear specification of volumes of planned investment included in the forecasts used to set the price control, regular reporting of volumes and potential deductions of pre-funded costs as part of the a subsequent price control. For RP6 a specification of volumes of planned investment is set out in Annex P. These planned investments provide a reference point for the estimation of pre-funded costs in the next price control.
- iii) To allow for the assessment of pre-funded costs in RP7, NIE Networks would be asked to submit to the Utility Regulator two pieces of information:
 - (i) *Forecast network investment.* This is NIE Network's estimate of its expected network investment requirements for the RP7 price control period.
 - (ii) *Pre-funded costs.* This is an estimate of the value of network investment in the forecast network investment which does not need to be included as part of the network investment requirements in the calculations and the network investment strategy that was assumed for the purpose of setting the RP6 price control.
- iv) For RP7 a preliminary assessment of pre-funded costs will be made on the basis on the best available forecasts submitted with the NIE Networks business plan. Because this will continue to include estimates of future investment we will review the assessment of pre-funded costs on the basis of the final out-turn figures for RP6 and take account of our updated analysis in the setting the subsequent (RP8) price control.
- v) The assessment of pre-funded costs is not a purely mechanistic exercise of comparing volumes of different types of network investments. It is partly a qualitative exercise, drawing on information on how NIE Networks has adapted its investment and asset management over time.

Application of deferral and substitution to output volumes

14.16 Much of the planned network investment in RP6 delivers the refurbishment or replacement of existing assets and the expected outputs are defined by volumes as opposed to specific assets. Much of this activity is not unique to a single price control, but is expected to continue at similar rates in future price controls. In these circumstances, the application of substitution within a price control and the mechanism to defer investment between price controls could give rise to three key risks to consumers:

- i) A company might decide to reduce the volume of assets refurbished or replaced during the Price Control period but carry out the work early in a subsequent period. This type of short term deferral is not necessarily in the interest of consumers. It might create a perverse incentive for the company to inflate the activity volumes proposed in a Price Control to then benefit through the deferral mechanism. Since the assets to be refurbished or replaced are not itemised, consumers risk paying for the same work twice.

- ii) A company might decide to refurbish or replace items with a low unit cost in one price control and defer the replacement of higher unit cost items to a subsequent price control. The company would obtain a financial benefit through the cost risk sharing mechanism and then make a case for an increase in the unit cost for work which is carried out in a subsequent price control. Consumers might be equally well served if the company delivered at an average unit rate over the medium term rather than at a lower unit rate in the short term.
- iii) Through the substitution mechanism, a company might decide to substitute out items whose likely cost is higher than the unit rate implied in Annex P to fund additional items where the likely cost is expected to be lower than the unit rate implied in Annex P. This could suggest that the price control outputs have been delivered at lower cost while maintaining the value of unit rates to inform the determination of subsequent price controls. However, consumers may have been better served if the substitution had not taken place.

14.17 Overall, a future assessment of deferral and pre-funded costs could be made more complex by the introduction of a substitution mechanism. In view of these risks it is appropriate to develop the principles we would apply when determining the outcome of the substitution and deferral mechanisms at the end of RP6. We have set out initial proposals in the section with a view to further engagement and discussion in advance of the final determination.

- i) We would expect the company to demonstrate that there is fair value in the substitution of investment and associated volumes within sub-allowances and between the allowances. As a starting point, we would use the lower of the unit cost in Annex P or the revealed unit cost in RP6 to determine fair substitution.
- ii) We would expect the company to demonstrate that unit costs revealed in RP6 associated with substitutions are the basis for unit costs requested in RP7. In principle, we would not expect unit costs to rise between Price Controls. Where there is an increase in unit costs between Price Controls we might conclude that this includes an element of deferral of investment.
- iii) Where the company chooses to substitute out activities in RP6, we would not expect the volumes in RP7 to be more than the run-rate originally planned for in RP6. If the increase in planned volume in RP7 is greater than this, we might conclude this includes an element of deferral of investment.
- iv) If the volume of outputs delivered in RP6 is lower than the volumes identified in Annex P, other than that necessary for substitution within the limits of the substitution mechanism, we are likely to conclude that this represents deferral unless there is a similar reduction in the planned volume in the subsequent price control.
- v) Any increase in direct network investment over the RP6 allowance would be subject to the cost risk sharing mechanism only irrespective of whether there

is an increase in activity volumes in RP6 or if additional activities are undertaken by the company.

- 14.18 Inherent in this approach is the over-riding principle that out-performance which is shared between the company and consumers should also reveal sustainable activity reductions and unit cost reductions from which consumers benefit when establishing the allowances in subsequent price controls.
- 14.19 The application of these principles in the assessment of the substitution mechanism and the determination of deferral for RP7 will not necessarily be a mechanistic process. A preliminary assessment will be undertaken for the draft and final determinations for RP7. The final determination of deferral for the RP6 Price Control period will be made once final out-turn figures for the period are available. It will be taken into account in the determination of revenues as soon as is practical, adjusted to be NPV neutral. The decision will be confirmed in the final determination decision for RP8.
- 14.20 The costs and unit rates set out in Annex P are stated before the application of the frontier shift. When we consider the application of the substitution and deferral mechanism in RP6, we will consider the profile of investment and apply the relevant frontier shift factor.
- 14.21 The overall programme of planned network investment presented by the company in its business plan was distributed uniformly across the RP6 period. Our draft determination is also based on a uniform rate of direct network investment over the price control period. It would be possible for the company to delay investment yet deliver all the planned investment within the price control period. However, this can only be done at some increased risk to consumers whether or not that risk is realised or whether or not it has a material impact on service in any one year within the background fluctuation in service year on year. In view of this, we will consider the option of retrospectively re-profiling the allowances for planned network investment in RP6 to reflect the profile of investment delivered if delivery is back-end loaded and set out our conclusions on this issue in the final determination.

Customer Minutes Lost (CML) / Network reliability

Introduction

- 14.22 For RP6 we propose to introduce a reliability incentive scheme.
- 14.23 Reliability incentives have been introduced by many regulators of electricity distribution and transmission, both in the UK and internationally. For example, Ofgem in GB currently have in place the Interruption Incentive Scheme (IIS), which provides a financial incentive to DNOs to improve reliability based on the number of customer interruptions per 100 customers and the average minutes without power per customer.
- 14.24 Focusing on reliability can help balance other regulatory objectives, most notably low prices for customers. For example, while we expect NIE Networks to be efficient and ensure that prices are no higher than necessary, through regulatory mechanisms such as benchmarking, this may adversely encourage NIE Networks to reduce reliability, which would be at the detriment of customers.
- 14.25 Therefore, by introducing reliability standards and incentives, we can ensure that NIE Networks manage the trade-off between costs and reliability appropriately and in the best interest of customers.
- 14.26 At RP5, we had in place a guaranteed standards of service requirement of 24 hours which NIE Networks must meet but not a reliability incentive scheme.⁹⁰
- 14.27 For RP6, we have conducted a comprehensive review of regulatory precedent⁹¹ and designed a reliability incentive which follows regulatory best practice. We plan to implement the reliability incentive in 2018/19, and look forward to seeking views from stakeholders in due course.
- 14.28 Further details on our reliability incentive can be found in Annex M.

Regulatory best practice

- 14.29 Based on our review of regulatory precedent we have come to a set of “best practices” that we use to develop our proposed reliability incentive:

Reliability incentive design

- 14.30 NIE Networks already reports on its performance in terms of CML and CI. Ongoing performance reporting should be complemented with an incentive scheme with financial implications (i.e. bonuses / payments).
- 14.31 While it is useful to report performance at a disaggregated level (i.e. by LV, HV and EV sub-systems), performance targets should be set a more aggregate level.

⁹⁰ Although a reliability incentive was proposed in our RP% draft and final determinations but was not followed through by CC.

⁹¹ See Annex E.

Target setting

- 14.32 Targets should provide distributors with a challenge but at the same time should be realistic and achievable.
- 14.33 Regulators tend to set targets based on benchmarking distributors with one another and historical averages. The weighting applied to benchmarking and historical averages can differ across sub-systems.
- 14.34 It is important that we set reliability targets in a transparent manor so that companies are provided with a degree of long term certainty regarding what targets they will be asked to achieve.

Willingness to pay studies (WTP)

- 14.35 Reliability targets and incentive rates should be set using WTP studies where available. These studies will provide an indication of the value customers put on reliability.

Two-sided symmetric incentive

- 14.36 A two-sided symmetric incentive ensures that there is no cliff-edge effect. This is where a company may not invest in reliability when they are performing close to the target if they are not able to recover the costs of the investment through an incentive reward. Even if it could lead to an increase in reliability.
- 14.37 This approach also offers impartiality between the financial implications for customers and distributors.

Revenue exposure

- 14.38 Revenue exposure tends to fall in the region of 1.5% to 7% across the case-studies studies examined.

NIE Networks' RP6 reliability incentive proposal

- 14.39 NIE Networks have proposed a reliability incentive based on CML, where 1.25% of annual distribution revenue is exposed.
- 14.40 Individual targets are set for planned and unplanned CML and then combined into one CML target by applying a 100% to unplanned CML and a 50% weight to planned CML.
- 14.41 The incentive rate has been calculated based on the Value of Loss Load (VOLL), which provides a proxy for the average willingness of electricity consumers to pay (WTP) to avoid an additional period without power. This is often used by regulators, including Ofgem, when designing a reliability incentive.
- 14.42 The VOLL used by NIE Networks is £17.50 per kWh, which is an estimate of VOLL for domestic customers from an ESRI report.⁹² However, it appears that NIE

⁹² Tol, R.S.J et al. (2010). An Estimate of the Value of Lost Load for Ireland.

Networks' have incorrectly not converted the figure in the report from euros per kWh to pound sterling per kWh. As a result, the figure used is too high in magnitude.

- 14.43 The unplanned CML target is set at 61.4 and the planned CML target is set at 58. The company has set its targets using a 10-year average to mitigate for any year-on-year fluctuations.
- 14.44 NIE Networks' calculated CML incentive rate is approximately £0.28 million for unplanned CML and £0.14 million for planned CML. Based on 1.25% of annual distribution revenue, which NIE Networks have estimated to be £2.4 million, this equates to +/- 6 CML either side of their target for both unplanned and planned CML.
- 14.45 Our review of regulatory precedent highlighted that there are a number of areas where NIE Networks' reliability incentive is not in accordance with best practice, and can therefore be improved upon:
- The CML target set by NIE Networks uses a 10-year average, which we feel is overly cautious. While we agree that a 10-year average may be appropriate for EHV outages as they incur less frequently than LV and HV outages, we do not consider a 10-year average is appropriate for LV and HV faults. Regulatory precedent suggests that a 4 year average is more than sufficient to capture year-on-year volatility.
 - The unplanned CML target has been set using historical averages alone, with no attempt at benchmarking with other GB DNOs. Regulatory precedent highlights that a combination of individual company historical averages and benchmarking with other distributors is the most appropriate approach to take when designing a reliability incentive.
 - A dead band zone where no bonuses or penalties are served has not been included within the design. Given RP6 will be the first regulatory period a reliability incentive has been introduced in Northern Ireland, a dead band zone eliminates any unnecessary risk on NIE Networks and customers.

RP6 Reliability Incentive

- 14.46 We have designed a reliability incentive that we believe is transparent, offers a challenging yet realistic target for NIE Networks over the course of RP6, and is in accordance with best practice.
- 14.47 We have calculated separate unplanned and planned CML targets, which in line with Ofgem's approach at RIIO-ED1. Severe weather events have been excluded from CML as these events are outside the control of NIE Networks.
- 14.48 An event is classified as a severe weather event when a minimum, verified, number of incidents affecting the distribution high voltage network linked to severe weather conditions has occurred within a 24 hour period.
- In Northern Ireland, the "commencement threshold number" means 13 times the average daily fault rate experienced by NIE Networks' distribution high voltage network.

- In GB, severe weather events that cause the daily higher voltage fault rate to go beyond the category 1 threshold of eight times each DNO's daily average higher voltage fault rate are excluded from CML and CI figures.

14.49 As a result, there is a slight divergence between the definition of a severe weather event in GB and Northern Ireland. We mitigate for this by moving the benchmark from the upper quartile company, as used by Ofgem at RIIO-ED1, to the average performing company (as discussed below).

14.50 Based on regulatory best practice, the reliability incentive we propose is designed as follows:

- **A symmetric incentive around a set target.** The reliability incentive is structured as a symmetric incentive. A 'dead band' zone has been included whereby no reward is received or no penalty is paid. This is set at 5% either side of the target for unplanned and planned CML. This should remove any excessive risk from customers and NIE Networks.
- **The unplanned CML target has been set based on historical average and benchmarking with GB DNOs.** We have taken the approach Ofgem have taken at RIIO-ED1 by applying a 75% weight to the benchmark CML target and 25% to the historical average. Given customer WTP for unplanned outages is greater than planned outages, we have allocated two thirds (2/3) of total distribution revenue exposure to unplanned CML. Our approach to calculating historical averages and benchmarking is discussed below.

(i) **Historical averages.** The historical averages have been calculated based on the approach taken by Ofgem at RIIO-ED1. For LV and HV we take a four year historical average, and for EHV we take a 10 year historical average. A 10 year average is chosen for EHV faults to reflect the fact that there are relatively few incidents each year at the 132kv and EHV voltages, which can lead to greater volatility relative to HV and LV faults.

(ii) **Benchmarking.** Ofgem consider that CML per CI offers a good metric for benchmarking as this provides an average restoration time for each CI, which DNOs can influence. Ofgem calculate a separate CML per CI benchmark for HV, LV and EHV. We have opted to assess CML per CI on an aggregate basis, and use the average distributor performance as the benchmark.⁹³ Ofgem use an upper quartile benchmark for HV outages, which are the largest contributor to CML and CI, and an average benchmark for LV and EHV outages. We consider using an average benchmark across all sub-networks (HV, LV and EHV) instead of the upper quartile benchmark is appropriate to mitigate for any slight differences in reporting across distributors. To calculate the final CML benchmark target for NIE Networks we multiply the average CML per CI across distributors by NIE Networks' 5-year average CI. The use of a 5-year average CML per CI, and CI, is to reflect the differences in our approach to historical

⁹³ We use the 5-year average CML per CI for each distributor over the period 2011/12 to 2015/16 to derive the benchmark.

averaging (discussed above) across different distribution sub-systems
- HV (4 year average), LV (4 year average) and EHV (10 year average).

- **Planned CML target is based on a 5 year historical average⁹⁴.** Given planned CML will be correlated with the level of capital investment, which will vary across distributors, benchmarking with GB DNOs would not be appropriate in this instance. We have chosen a 5 year historical average to reflect the differences in our approach to historical averaging across different distribution sub-systems - HV (4 year average), LV (4 year average) and EHV (10 year average). Given customer WTP for planned outages is less than unplanned outages, we have allocated one third (1/3) of total distribution revenue exposure to planned CML.
- **Target.** Both planned and unplanned CML targets are challenging but also realistic and achievable. We have also attempted to subvert any unnecessary risk away from NIE Networks and customers by including a dead band zone. We have applied the target over a glide path rather than as a P^0 adjustment to reflect the fact that there is likely to be a lag between the implementation of the reliability incentive and improvements in CML.
- **VOLL based on WTP studies.** We have set the VOLL, used to derive the cost of CML, using the most recently published estimate of VOLL of domestic customers in Northern Ireland of £14 per kWh.⁹⁵
- **Revenue exposure and risk.** Given the reliability incentive will be implemented for the first time in Northern Ireland during RP6 we have set the annual distribution revenue exposure to 1.5%, which is towards the lower end of the range identified in our regulatory review.

14.51 NIE Networks' unplanned and planned CML targets are displayed in the table below. As mentioned, we propose to introduce the reliability incentive in 2018/19 to avoid any seasonal effects.

14.52 The unplanned CML target decreases by approximately 8% from the company's current average CML, which we believe is both challenging yet realistic and achievable.

DNO	Current Average	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Unplanned CML target	58.31	57.54	56.77	56.00	55.23	54.46	53.70
Planned CML target	56.76	56.76	56.76	56.76	56.76	56.76	56.76

Table 71: NIE Networks' unplanned and planned CML targets during RP6

14.53 We propose to use the Reckon VOLL estimate of £14 per kWh to derive CML incentive rates. This estimate provides the most recent estimate of VOLL in Northern Ireland.

⁹⁴ With further more recent data we may be in a position to update for the final determination.

⁹⁵ Reckon, 2012. Desktop review and analysis of information on Value of Lost Load for RIIO-ED1 and associated work.

- 14.54 We have used this estimate of VOLL to arrive at a cost estimate for unplanned CML of approximately £208,311. The cost estimate of planned CML is 50% of this amount at £104,156 to reflect the fact that customers assign less value to pre-arranged outages.
- 14.55 Using these figures and total annual exposed revenue we calculate the CML cap and floor of approximately +/- 11.4 CML either side of the unplanned and planned CML targets.
- 14.56 The assumptions and calculations we have used to arrive at these estimates are presented in the tables below:

Input Assumptions		
Variable name	Figure / Calculation	Source
Annual electricity consumption	7,820,605,400 kWh (2014/15)	Department for Business, Energy & Industrial Strategy, 2016.
Number of meters installed	837,710 (2014/15)	Department for Business, Energy & Industrial Strategy, 2016.
Customer numbers	855,575 (2014/15 for consistency)	NIE Networks Benchmarking Submission
Value of lost load (VOLL)	£14 per kWh	Reckon RIIO-ED1 review report ⁹⁶
% of total distribution revenue exposed	1.5% = £2.66 million	Based on average annual distribution revenue over the RP6 period, in 2015/16 prices) ⁹⁷

Table 72: Input assumptions and calculations used to calculate the CML incentive rate

⁹⁶ Reckon, 2012. Desktop review and analysis of information on Value of Lost Load for RIIO-ED1 and associated work.

⁹⁷ Provisional figure which be updated for final determination. As a result, CML cap/floor will also be updated for final determination.

Calculations		
Variable name	Calculation	Details
Average consumption per customer per hour	1.04 kWh	Annual electricity consumption / customer numbers / total hours in a year
Cost per hour per customer	£14.61 per kWh	VOLL * Average consumption per customer per hour
Cost of customer hour lost	£12,498,684	Customer numbers * cost per hour per customer
Cost of customer minute lost (unplanned)	£208,311	Cost of customer hour lost / 60
Cost of customer minute lost (planned)	£104,156	Cost of unplanned CML * 0.5
Unplanned CML cap/floor	11.39 CML	(i) Unplanned CML revenue exposed = total exposed revenue * 2/3 = £1.77 million (ii) Unplanned CML cap/floor = (unplanned CML revenue exposed / cost of unplanned CML) + (difference between unplanned CML target and dead band)
Planned CML cap/floor	11.35 CML	(i) Planned CML revenue exposed = total exposed revenue * 1/3 = £0.89 million (ii) Planned CML cap/floor = (planned CML revenue exposed / cost of planned CML) + (difference between planned CML target and dead band)

Table 73: Input assumptions and calculations used to calculate the CML incentive rate

- 14.57 Our proposal is summarised in the two charts below for unplanned and planned CML.
- 14.58 It is important to note that the tram lines either side of the target may potentially move after the draft determination as they are determined based on total RP6 distribution revenue which will only be finalised at final determination.
- 14.59 In accordance with NIE Networks, we propose that the reliability incentive scheme commences in 2018/19 to avoid any seasonal effects:
- i) The dead band zone are shown by the dotted green lines.
 - ii) The cap and floor are illustrated by the solid green lines.
 - iii) The solid blue line shows historical outturn CML up until the end of 2015/16, and target CML through the RP6 period.
- 14.60 Further detail on the new incentive for reliability is included within our Technical Annex M – Reliability Incentive.

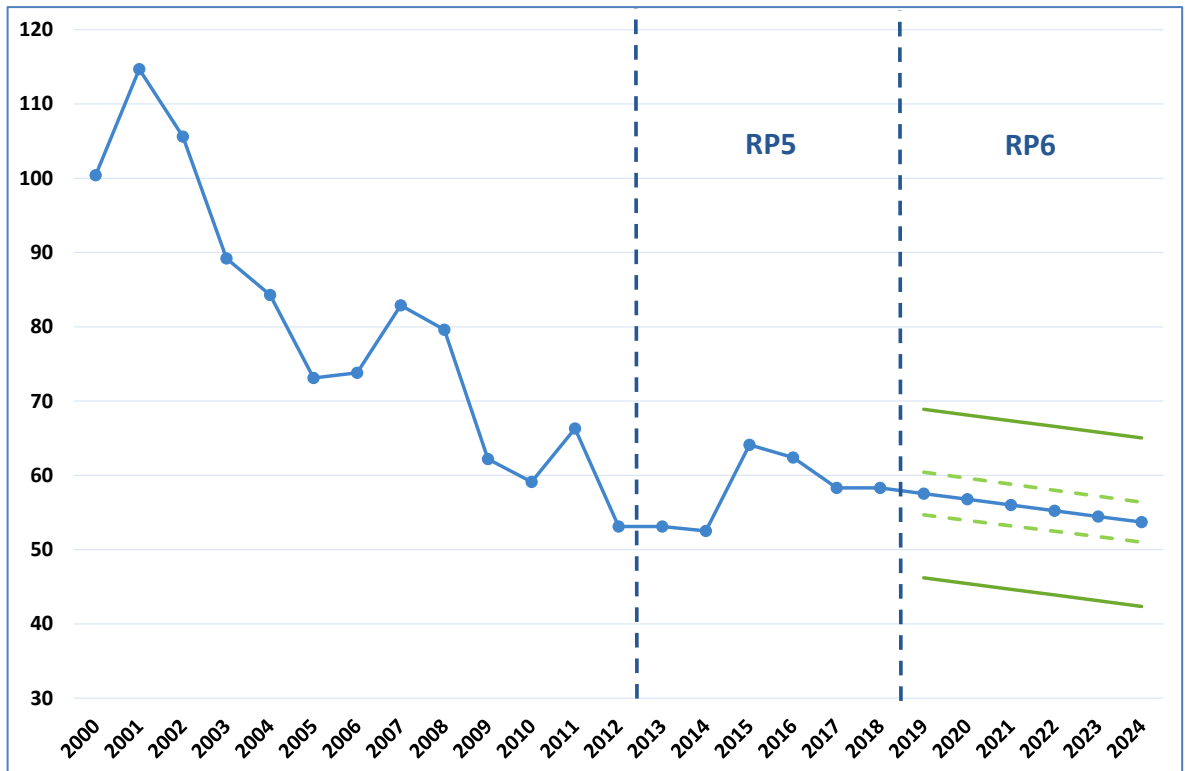


Figure 15: Unplanned CML reliability incentive

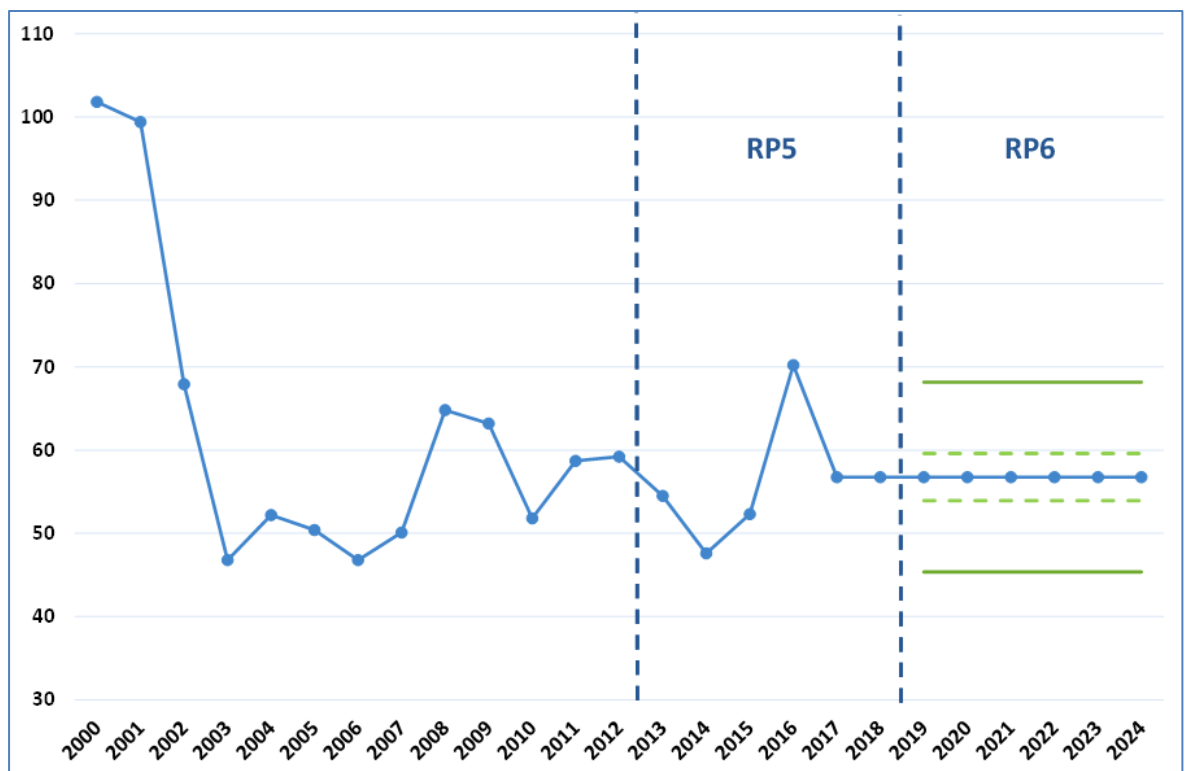


Figure 16: Planned CML reliability incentive

Revenue protection

- 14.61 We agree with NIE Networks that the current incentive arrangement should be retained within RP6. There is to be no change with regards these arrangements. NIEN would continue to keep 50% of the revenues recovered from premises that are not supplied with electricity from a registered supplier.
- 14.62 However we do not agree with the proposed new incentive scheme. We are in agreement that it would be ideal to have an incentive that worked to incentivise NIE Networks to keep losses from theft as low as possible. But in our view the proposed arrangement would not achieve this.
- 14.63 Under the proposed arrangement NIE Networks would not be incentivised to actively deter theft. Rather it would only be incentivised to identify and stop theft once it has already occurred. So, NIE Networks would earn more money under its proposed scheme if 5% of customers were involved in theft and it identified and stopped half of this compared to it taking pro-active measures to limit theft in the first place to only 2% of customers.
- 14.64 Ideally we would put in place an incentive linked to losses which would in theory put a robust incentive on NIE Networks to stop theft in the first place. However we agree with NIE Networks that such a scheme would be too complex to design.
- 14.65 In considering this issue we are concerned that theft became a serious issue in Northern Ireland and the level of proactive engagement to prevent this was not what we would have expected. We do not think the proposal from NIE Networks would address this concern in a strong enough manner.
- 14.66 The UR has two work-streams in place to address the theft of electricity: the meter replacement programme for theft and the Energy Theft Codes of Practice.
- 14.67 The meter replacement for theft programme targets premises suspected of energy theft. We have agreed a volume of 20,000 meters at a unit price of £117 for this work-stream. The unit costs of £117 are higher than a standard keypad installation of £73.66. The higher costs for a meter replacement for theft meter are to cover the additional RPU overheads for this type of work.
- 14.68 In addition the Energy Theft Codes of Practice aim to protect consumers from the safety issues and costs related to energy theft. To do this we propose to use the Energy Theft CoP to provide transparency on the obligations on electricity and gas distribution network operators and suppliers to work together to establish and implement detailed and best-practice industry procedures to prevent, detect and investigate energy theft.
- 14.69 The Energy Theft Codes of Practice is re-structuring and improving activities that are already being carried out. We do not expect that this will lead to any additional costs. If roles and responsibilities are clarified and procedures are streamlined across the sectors we would expect that this could reduce overall costs.

- 14.70 We have proposed an Energy Theft Compliance Report within our Energy Theft Code of Practice consultation. This proposal will require NIE Networks to set out its view on electricity theft levels/issues and what actions it is proactively taking to prevent theft.

Customer service incentive

- 14.71 As discussed above at paragraph 4.12 NIE Networks has expressed a desire to continue to work with the Utility Regulator to develop its existing customer surveys, perhaps to facilitate the consideration of a RP7 incentive around customer satisfaction scores.
- 14.72 Rather than rush to introduce a customer service incentive at RP6 without any accompanying time series of NIE Networks' performance, we have included new customer advocacy and survey metrics within our RP6 developmental objectives.
- 14.73 Once we have established a reliable time series of customer service performance, especially around such fundamentals as customer satisfaction and customer advocacy, we intend to review the need for a customer service incentive around RP7.

Distribution losses incentive

- 14.74 The company does not believe it would be appropriate to introduce a loss of electricity incentive during RP6, since NIE Networks believes it would be very difficult to establish a baseline for a losses incentive during RP6.
- 14.75 The Utility Regulator agrees with the above.

15 Future reporting requirements

Worst Served Customers (WSC) definition

- 15.1 See paragraph 4.36 where the WSC is included alongside other important developmental objectives for the RP6 period.

Asset Health and Load Indices

- 15.2 See paragraph 4.36 where such indices are included alongside other important developmental objectives for the RP6 period.

CML / Reliability Incentive

- 15.3 See paragraph 14.22 For RP6 we propose to introduce a reliability incentive scheme where we detail our proposed reliability incentive and its introduction during the RP6 period.

Annual Cost Reporting

- 15.4 We expect to review the performance of NIE Networks for the entire RP5 period and produce a Cost and Performance report towards the end of 2018. We expect that the report will review NIE Networks performance on opex, capex and outputs for the RP5 period.
- 15.5 We plan after the review of RP5, to produce an Annual Cost and Performance report each year for RP6, to monitor progress of performance against regulatory allowances, to enable better transparency for all stakeholders. As RP6 commences mid way through the normal reporting cycle, which is normally at the end of March, we will need to consider whether it is appropriate to review and report on either a ½ year or 1 ½ years performance.

16 Licence implications

Licence modifications and appeals (LMA) process

- 16.1 The relatively new LMA process requires we consult regarding the RP6 licence using a 2-stage process. The first stage shall end x28 days after our final determination publication and Licence Modification Notice issue on 28 June 2017. The second stage ends 29 September 2017 exactly x56 days after our Licence Notice of decision on how to proceed is published on 4 August 2017.
- 16.2 Our second stage ends just prior to 1 October 2017, just in time to ensure the RP6 licence (assuming NIE Networks accepts our final determination) is in place to ensure the RP6 effective date begins on the first day of the new RP6 regulatory period.
- 16.3 With the above end date in mind, there is a small period to allow due consideration of responses to our licence consultation of the RP6 licence modifications. As stated previously at paragraph 2.26, we consulted with the company and stakeholders concerning our amended RP6 timetable (see Figure 1 above).
- 16.4 We intend working closely with the company and stakeholders during the 8-week consultation period of this draft determination to help develop the detail of any licence modifications.
- 16.5 Our preference is to avoid lengthy, complicated modifications where the previous RP5 licence modification process (which spanned over two years) already landed on many robust uncertainty mechanisms, for example. That said, a new reliability incentive mechanism will require due consideration of the extent to which a licence modification is required and the extent to which parties may rely upon an off-Licence spreadsheet mechanism to enable any rewards and penalties.
- 16.6 Likely RP6 workstream candidates for licence modifications include:
- Reliability incentive
 - Substitution mechanism
 - Contestability
 - Connections charge pass-through

17 Next steps

RP6 draft determination consultation

- 17.1 The Utility Regulator would like to invite all interested stakeholders to attend a workshop on the 28 April 2017 at 10:00 to discuss the RP6 draft determination.
- 17.2 If you would like to attend, please email simon.scott@uregni.gov.uk by 21 April 2017.

How to provide feedback

- 17.3 This is an open document for consultation on the RP6 draft determination. We have not posed any specific questions in this report. Instead we invite stakeholders to express a view on any particular aspect of our draft determination.
- 17.4 If you wish to submit a written response this should be received **no later than the 19 May 2017 at 5pm** and should be addressed to:

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- 17.5 Individual respondents may ask for their responses in whole or in part, not to be published, or that their identity should be withheld from public disclosure. Where either of these is the case, we will ask respondents to also supply us with the redacted version of the response that can be disclosed.
- 17.6 As a public body and non-ministerial Government department, we are bound by the Freedom of Information Act (FOIA) which came into full force and effect on 1 January 2005. According to the remit of FOIA, it is possible that certain recorded information contained in responses can be put into the public domain. Hence, it is now possible that all responses made will be discoverable under FOIA – even if respondents ask the Utility Regulator to treat responses as confidential. It is therefore important that respondents note these developments and in particular, when marking responses as confidential or asking the Utility Regulator to treat responses as confidential, should specify why they consider the information in question to be confidential.

Annexes

[Annex A – CEPA Regional Wage Adjustment](#)

[Annex B – CEPA Efficiency Modelling](#)

[Annex C – Frontier Shift: real price effects & productivity](#)

[Annex D – GEMSERV Market Ops Non-Network IT Assessment](#)

[Annex E – GEMSERV Non Network IT Assessment](#)

[Annex F – Pensions Annex](#)

[Annex G – GAD report on Pensions](#)

[Annex H – Rate of Return Adjustment Mechanism](#)

[Annex I – Rate of Return Adjustment Mechanism Model](#)

[Annex J – First Economics report](#)

[Annex K – RP5 financial model \(latest position\)](#)

[Annex L – RP6 financial model](#)

[Annex M – Reliability Incentive](#)

[Annex N – Metering](#)

[Annex O – Assessment of Network Investment Direct Allowances](#)

[Annex P – Planned Network Investment Volumes and Allowances](#)