COMPETITION COMMISSION

NORTHERN IRELAND ELECTRICITY LIMITED PRICE DETERMINATION

A reference under Article 15 of the Electricity (Northern Ireland) Order 1992

Provisional determination

Notified: 8 November 2013

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Summary

Background

1. The Northern Ireland Authority for Utility Regulation (the Utility Regulator (UR)) issued a Price Control Determination for Northern Ireland Electricity Limited (NIE) on 23 October 2012 in respect of NIE's Licences for transmission and distribution, together with proposed draft licence modifications. NIE rejected the licence modifications, and on 30 April 2013, the UR made a reference to the Competition Commission (CC). In accordance with Article 15(1) of the Electricity (Northern Ireland) Order 1992 (Electricity Order) the reference requires the CC to consider:
   - *(a)* whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest;
   - *(b)* whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences; and
   - *(c)* if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the Conditions of each Licence.

2. NIE is the owner of the electricity transmission network in Northern Ireland and the owner and operator of the distribution network. NIE's transmission and distribution network contains several interconnected networks of overhead lines and underground cables which are used for the transfer of electricity to approximately 840,000 consumers (of which nearly 780,000 are domestic customers) via a number of substations. NIE derives its revenue principally through use of distribution system charges levied on electricity suppliers; and transmission services charges levied on the System Operator for Northern Ireland (SONI). These charges are ultimately

recovered from final consumers; network charges typically make up around 20 to 25 per cent of the final consumer's electricity bill. NIE is no longer involved in the generation of electricity, nor in the purchase and supply of electricity to customers.

3. NIE was acquired by ESBNI Limited (ESBNI), a subsidiary of the Electricity Supply Board (ESB, the licensed transmission asset owner, distribution system operator and meter operator in the Republic of Ireland), in December 2010.

4. The UR has controlled charges for transmission and distribution by setting the revenues that NIE is allowed to raise during the following price control period. The price control determination sets these allowed revenues and proposes amendments to NIE's Licences to implement this. The UR also approves NIE's tariffs, but that process is not the subject of this redetermination.

5. In its final RP5 determination document, the UR set out NIE's allowed revenues for transmission and distribution, for the period 1 January 2013 to 30 September 2017. It said that the revenue was set at a level to allow the company to recover operating costs, depreciation and a reasonable return on investment. NIE told us that it had been compelled to reject the Final Determination because it would allow insufficient revenues to finance the activities which were necessary to enable it, in the short term, to provide a safe and reliable electricity transmission and distribution service to today's electricity customers, and in the longer term, to invest in the maintenance and development of the skills and assets required to provide such a service to future electricity customers.

6. We are therefore required to undertake a redetermination in accordance with the terms of reference. Our starting point is to assess whether the existing RP4 price controls operate in the public interest. The RP4 price control ran, originally, from

1 April 2007 to 31 March 2012 (RP4). However, in 2011 the UR announced delays in the implementation of the RP5 price control, and it sought to extend the RP4 price control.

7. In making our redetermination of whether any particular matter operates against the public interest, we are required by Article 15(7) of the Electricity Order to have regard to the duties imposed on the UR. The public interest scheme in its entirety as set out in the Energy (Northern Ireland) Order 2003 (the Energy Order), the Electricity Order and Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 (the EU Electricity Directive) is extensive. It provides, in addition to the principal objective of protecting the interests of consumers (where this includes both current and future consumers including business as well as domestic users), for a detailed set of more specific objectives and further considerations to which the CC must have regard. These objectives include the need to secure that all reasonable demands for electricity are met, that licence holders are able to finance their activities, and the need to protect the interests of vulnerable customer groups.

8. At least some of these additional objectives and considerations may, properly understood and in terms of their substance, be part and parcel of an overall objective to further the interests of consumers. We have balanced and attached appropriate weight to specific public interest factors where the particular facts and evidence before us have given us reason to do so. In addition, we take account of other factors where relevant to the particular issue, which will include (among other considerations) the Northern Ireland Government's aspiration to have 40 per cent of electricity generated from renewable sources by 2020.

9. The approach we have adopted is to consider for each aspect of the price control conditions whether it operates against the public interest and, if so, which is the best

alternative available (if any) that will address the adverse effect, and best serve the public interest. This includes the determination of appropriate allowances and any consequent adjustments arising from redesign of the price control. We then consider whether the overall effect of our proposals operates in the public interest or whether any aspects or the overall package should be modified.

10. For our redetermination, we have used the best data available to us, which meant that in some cases we used data that had been updated since the UR reached its determination. We also engaged consultant engineers, BPI, to advise us on NIE's capex proposals, and a consultancy, Pelicam Project Assurance, to help us investigate issues relating to the Enduring Solution project and non-network capex.

The existing price control conditions and the public interest

11. In relation to the existing RP4 price controls, both the UR and NIE in their respective submissions to us said that there was agreement that the existing RP4 price control conditions were now against the public interest, principally on the basis that they were only intended to operate until 31 March 2012. The UR told us that the RP4 price control was not a good one, that continuation of the adapted RP4 approach under its 'pragmatic approach' was an interim solution without adequate legal certainty, and that continuation would not promote efficiency and economy on the part of NIE and consequently would not adequately protect the interests of consumers in respect of services provided and prices charged. NIE submitted that the existing price control conditions could no longer function effectively at all, and it argued that the interests of consumers required that a fresh assessment was made of the regulatory mechanisms and other tools that formed the basis of the price control going forward.

12. We provisionally determined that the Price Control Conditions in each Licence operate, or may be expected to operate, against the public interest for the following reasons:

(a) Application of the current price control conditions generates uncertainty:

- The UR and NIE are in disagreement over whether the Price Control Conditions continue to have legal effect. We think that the lack of formal definitions and specifications of important aspects of the price control algebra for the period from 1 April 2012 is not compatible with good administrative practice and may lead to further disputes between NIE and the UR in the future unless licence modifications are made. NIE, its investors, its customers and other stakeholders including the UR face considerable uncertainty over what price controls currently apply, how NIE should conduct itself, and what price controls will apply in the near future. NIE cannot plan or invest appropriately and further disputes could increase costs.

(b) Aspects of the price control design are not sufficient to protect the interests of consumers:

- The calculation of NIE's maximum regulated revenue according to the level of capital expenditure that NIE incurs may expose consumers to excessively high charges that reflect capital expenditure that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to network investment. We have provisionally determined that the public interest is better served by systems which, compared with cost pass-through, better incentivize NIE to enhance the efficiency of its capital expenditure.
- Cost pass-through for capex could also operate against the public interest because it may expose customers to unnecessarily high charges, arising from the possibility for NIE's sister company, NIE Powerteam, to charge inappropriately high charges to NIE for the work it carries on NIE's network.

- Where the incentive rates for outperformance differ between operating expenditure (opex) and capital expenditure (capex), this can create distortions in how NIE would organize its activities. In particular, under the RP4 price controls, the separate allowance schemes in relation to opex and capex provide NIE with unduly strong financial incentives to adopt working practices that favour capex-intensive practices over opex but which may not be efficient. In addition, the interaction of the opex and capex arrangements may lead to excessively high charges on consumers if NIE changes its working practices or accounting practices over time so as to reclassify opex as capex, even where its activities remain essentially unchanged. Changes in capitalization practices could lead to activities notionally funded through an opex allowance also being funded through capex.
- We consider that a benchmarking approach (ie setting opex allowances with reference to the costs of efficient comparators) provides a stronger incentive to operate efficiently than the incentives on opex efficiency under the RP4 controls. We have also identified that opex allowances should be adjusted for efficient indirect costs. In consequence, we have applied the benchmarking and indirect adjustment approach to allowances to opex allowances and other associated items, including revision of pension arrangements. Our provisional determination is that the current arrangements are against the public interest when this superior alternative is available.
- New capex allowances need to be set. Also, specific opex allowances need to be set for new, additional functions and items of opex that NIE has to be able to finance to achieve necessary functions.
- Additionally, the calculation of NIE's maximum regulated revenue according to the level of 'uncontrollable' operating costs that it incurs may expose consumers to excessively high charges that reflect excessive expenditure on

items treated as uncontrollable costs which NIE nonetheless has some influence over.

(c) The current price control conditions allow an excessive cost of capital:

- We provisionally determined that the current allowance for the cost of capital in the price control conditions is too high, which may expose consumers to excessively high charges.

(d) The duration of the regulatory asset base (RAB) for short-lived assets (specifically tree cutting) operates against the interest of future customers:

- We note that investments are currently added to a 40-year RAB. We provisionally determined that this operates against the public interest for significant expenditure on assets which have a much shorter life. We consider that this applies to tree cutting, because in our view it is inappropriate for future generations to be paying the costs of investments which have such a short life in relation to the period over which they are being depreciated for pricing purposes (40 years). We also consider that certain non-network capex investment (largely covering IT) should also be placed in a short-term RAB rather than expensed.

13. Our terms of reference also require us to consider whether the continuation of each Licence operates, or may be expected to operate, against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences. We provisionally determined that the continuation of the existing Licence absent further conditions will operate against the public interest. This is because we found that the UR currently receives insufficient reliable information in order for it to regulate NIE in a fully effective manner and the more effective involvement of other stakeholders who would benefit from transparency will help improve regulatory decisions and controls.

Provisional determination on modifications of the licence conditions

14. We now set out our findings in relation to aspects of the price control and our provisional determination of modifications to the licence conditions.

15. We provisionally determined that significant changes to the design of the price control will address the effects adverse to the public interest. Our provisional determination, while still an example of RAB-based incentive regulation, also differs substantially in several respects from the arrangements proposed by the UR in its RP5 determination document.

16. We have provisionally determined that there should be separate revenue controls for transmission and distribution, in line with the separate Licences.

17. We propose a new price control for NIE calculated by reference to our assessment of NIE's expenditure requirements (if it were to operate efficiently) in the period from 1 April 2012 to 30 September 2017, with arrangements that have the effect of sharing between consumers and NIE's investors the differences between our assessment of NIE's expenditure requirements and NIE's out-turn expenditure in a 50:50 distribution for both opex and capex. Our proposed approach provides some protection to consumers against the risks that our assessment overestimates NIE's expenditure requirements. It also provides some protection to NIE against the risk that our assessment underestimates NIE's expenditure requirements. We also sought to reduce the risk that the regulatory framework gives NIE financial incentives to favour unduly working practices and capitalization practices that enhance NIE's capex relative to its opex. The cost risk-sharing mechanism will not apply to elements of the new price control subject to full cost pass-through (eg licence fees) nor to costs for connection services funded by connection charges outside the scope of NIE's revenue control.

18. We have included a provision that the UR can make adjustments to NIE's revenues or RAB to protect consumers from exposure to any costs that are demonstrably inefficient or wasteful.

19. Under conventional RAB-based incentive regulation, there is a risk that a regulated company may defer investment projects for which it has received an allowance. The approach we provisionally determined is not to prevent investment deferral, some of which may be efficient, but rather to protect consumers from adverse financial consequences in the event of investment deferral. The approach is based on an expectation that, at future price control reviews, the determination of NIE's maximum revenue and RAB by the UR could be undertaken by reference to a policy that there should be no double funding of deferred network investment. Therefore, in subsequent price controls, we would recommend that NIE be required to identify any aspects of its forecast network investment which arise as a result of deferment or abandonment of investment that was included in the calculations we have used to set a new price control for NIE. These would be netted off its expenditure allowances for the subsequent price control period. This aspect of our provisional determination is intended to protect customers from the risk of facing charges for further work which has already been funded, as a result of deferment or abandonment of projects planned for RP5. While our determination cannot bind the UR in regard to how it regulates NIE in future price controls, our intention is to create a system which allows the UR to avoid double funding of deferred investments in future.

20. We provisionally determined that there should be provisions within NIE's licence conditions to allow the UR to adjust NIE's price control and RAB to allow funding for new investment projects to increase the capacity and capabilities of the transmission network (for projects not included as part of the cost assessment we have used for our determination). NIE will be able to apply to the UR on a project-by-project basis

for an increased allowance during the price control period, without having to wait for the UR's next price control review. For work to increase the capacity and capabilities of the distribution network, we have provisionally determined not to use any special adjustment mechanisms. Instead, we propose to set an upfront allowance in relation to distribution load-related expenditure, with the same cost risk-sharing arrangements as for other areas of NIE's expenditure.

21. Our provisional determination is that a form of volume driver mechanism is appropriate for NIE's capital expenditure in relation to electricity meters. This mechanism helps address substantial uncertainty about the volumes of metering investment that NIE will need to carry out. Any potential future transition to smart meters would be dealt with either by the change of law provision in the existing licence conditions (which we propose to retain) or a licence modification.

22. NIE imposes charges for new connections to its network (also known as customer contributions). At present an element of certain connection charges is 'subsidized' through NIE's RAB and revenue control. Our provisional determination is that costs relating to this subsidy from NIE's RAB should be recovered on a cost pass-through basis, as a temporary arrangement until 1 October 2014.

23. Under RP4, certain operating costs that NIE incurs are passed through, in full, to consumers. Our provisional determination is that licence fees should be treated as a cost pass-through item. However, in contrast to the RP4 arrangements, rates and wayleaves should not be subject to cost pass-through. Instead an upfront allowance and the cost risk-sharing mechanism described above will apply.

24. We propose that there would be no upfront allowance for costs relating to injurious affection but there should be a provision for the UR to make an allowance in the

future. This would be informed by the results of a forthcoming Lands Tribunal determination.

25. We also provisionally proposed the removal from the price control conditions of various elements which we consider to be redundant following changes to the Licences under the other modifications we have provisionally determined.

26. We have not proposed any schemes in the provisional determination covering: guaranteed standards; customer interruptions; electrical losses incentives; and arrangements for tackling the illegal abstraction of electricity. We propose changes to the treatment of income that NIE receives as part of revenue protection activities, so 50 per cent of the revenues that NIE receives each year from these activities should be shared with consumers.

27. We made a provisional determination of an annual allowance for NIE's indirect costs and costs for inspection, maintenance, faults and tree cutting (IMF&T) using the results from benchmarking analysis of the costs of NIE and 14 electricity distribution network operators (DNOs) in GB. This benchmarking analysis cuts across NIE's capital expenditure and its operating expenditure. We need to separate our allowance for indirect and IMF&T costs between opex and capex. We have done this by applying an allocation based on the decomposition of NIE's historical indirect and IMF&T costs between opex and capex.

28. One of the major areas of disagreement between the UR and NIE was over the level of core network investment NIE should be allowed to undertake. We assessed NIE's project by project submissions in this area, drawing on recommendations prepared by BPI (see paragraph 10). We also gave additional review to three projects which, for a variety of reasons, stood out to us as requiring additional scrutiny. We con-

cluded that some additional provision should be made for work to ensure NIE's compliance with ESQCR requirements. We were not persuaded that a large-scale pilot to accelerate network resilience work to deal with ice accretion was well justified or demonstrably cost effective, nor was an 11 kV network performance project to install remote control facilities. We made an allowance for non-recoverable alterations, but not for a project relating to Road and Street Works legislation which is not predicted to have any impact in the relevant period. We also made an adjustment to take out indirect costs to enable us to set a direct-only core network investment allowance. Finally, we adjusted our forecast to allow for the length we now propose for the RP5 period.

29. We provided for allowances for a variety of other specific items. In the case of some items, we have provisionally determined that NIE should be recompensed on a cost pass-through basis (eg capital cost of new connections and licence fees).

30. We made a forecast of how NIE's costs may compare to expected changes in general inflation (measured by the retail prices index (RPI)) over the period. This is because NIE's allowed revenues are indexed to increases in RPI but the costs of an efficient firm might be expected to follow a different path due to the combined effects of productivity and real price effects (RPEs). We estimated productivity improvements at 1 per cent a year for each of opex and capex. We have adapted allowances accordingly.

31. We examined a variety of issues around pensions. We provisionally determined that only the pension schemes which provide services exclusively to the regulated business of NIE should be included in our revenue control. We also provisionally determined that the deficits in the included schemes should be split into historic (up to 31 March 2012) and incremental deficits. The historic deficit will be funded 100 per

cent by consumers, with the deficit recovered over a period of 15 years; any incremental deficit arising will be funded 100 per cent by NIE. Deficit repair payments should be reviewed (and changed if necessary) following each triennial valuation. We provisionally determined that NIE should be refunded its stranded pension costs from RP4 over a period of 15 years, and also that the current split of early retirement deficiency contribution (ERDC) liabilities should be retained. We also provisionally determined that no adjustment to NIE's ERDC liability should be made for previous shareholder contributions. NIE's ongoing pension service costs are included in our indirect benchmarking and therefore no additional allowance is included for this item.

32. We examined the return that NIE should be allowed to earn on the RAB. We considered that this should be set equal to the expected cost of capital for NIE as a stand-alone company. We provisionally determined that NIE's real weighted average cost of capital for RP5 is 4.1 per cent.

33. The UR asked us to investigate whether changes in NIE capitalization practices meant that, in effect, customers had paid twice for certain activities in RP4. It suggested this might have arisen because the activities had been funded both through both an opex allowance and capex allowance, when NIE had changed its accounting treatment of certain activities from opex to capex. It considered that changes in capitalization practices might have contributed to apparently high levels of opex outperformance achieved by NIE in RP4. We concluded that the design of the RP4 price control could incentivize NIE to recategorize opex as capex in this way, because opex allowances were based on historic opex levels whereas capex was remunerated on a pass-through basis. We provisionally concluded that the RP4 price control was against the public interest because this could distort NIE's choices between opex and capex and could lead to NIE receiving inappropriate opex allowances.

34. However, on examining the facts, we were not convinced that NIE had engaged in reclassification of activities in this way to a significant extent. Changes in the balance of opex and capex activities reflected a mix of causes, including genuinely additional capex activities, the replacement of reactive opex with planned programmes of capitalizable activities, and improvements in information allowing replacement of assets to be better planned and better recorded. In addition, NIE will have achieved genuine opex efficiency improvements. We noted that the opex allowance in RP4 was never explicitly allocated to particular expenditures. Instead, NIE was incentivized to outperform on an overall opex allowance. We were satisfied that reasons other than simple recategorization of opex to capex accounted for at least a substantial part of the recorded outperformance and there was not a practical method to isolate any recorded opex outperformance arising specifically from recategorization. We also thought that any intervention to correct for such effects after the period in which the regulatory design applied could be harmful to investors' perceptions of regulatory stability. We provisionally determined to make no correction to opex outperformance in RP4.

35. With regard to regulatory reporting, as noted in paragraph 13, we provisionally determined that the current arrangements (absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences) were not in the public interest. We provisionally found that a step change in data reporting would bring significant benefits to stakeholders.

36. We provisionally determined that the introduction of a reporter function was not the best way to achieve this. Instead, we provisionally determined that a licence condition should be added which required NIE to report against the Ofgem Regulatory Instructions and Guidance (RIGs—these are used for reporting by the GB

DNOs), with a mechanism added that would ensure that only those RIGs relevant and useful to stakeholders were required.

37. We provisionally determined that a new five-year RAB should be adopted for all new capitalized tree cutting undertaken from the start of the RP5 period. We have also found that investments in certain IT under the non-network capex category should similarly now be put into a five-year RAB.

Duration of the price control

38. We propose that the new price control governs the calculation of tariffs applicable from 1 October 2014. We propose that the new price control should have a planned end date of 30 September 2017. However, we have provisionally determined that the price control should have the effect of also setting NIE's maximum regulated revenue in the period between 1 April 2012 and 30 September 2014. Therefore we have set out as part of the calculation of the new price control from 1 October 2014 arrangements to provide some compensation to consumers or NIE in relation to deficiencies in the calculation of NIE's maximum regulated revenue arising from the fact that tariffs have already been set for the period between 1 April 2012 and 30 September 2014.

39. We also propose, in case of a failure to implement a new price control in time when RP5 comes to an end, a licence modifications with the effect that, in the period from 1 October 2017, the restriction on NIE's maximum regulated revenue is replaced with a restriction of no increases to the tariffs set from 1 October 2016.

Financeability

40. The regulator has a duty to secure that licence holders are able to finance their activities which are the subject of obligations imposed under statute. Based on the

preliminary modelling that we have conducted, our provisional view is that our determination is consistent with NIE maintaining an investment grade credit rating.

41. However, we recognize that NIE's interest cover ratio is a potential source of concern. In considering possible actions to address this concern, NIE has several options. These may include limiting dividends, converting any non-regulated assets into cash, the issuance of index-linked debt to reduce cash interest expenses, and raising of finance in the form of equity or equity-like instruments (ie an equity injection).

Provisional determination of allowances

42. Our provisional determination of NIE's revenue allowances for each period from April 2012 to September 2017, expressed in constant 2009 prices, is set out in Table 1. We have presented our provisional revenue allowances separately in respect of Transmission and Distribution, reflecting our provisional decision that each should be subject to separate revenue control. Our total allowed revenues over 5.5 years are £1,009 million, of which £846 million relate to distribution and £163 million to transmission.

TABLE 1 **CC provisional determination: estimated revenue allowances**

£ million (constant 2009 prices)

Start of period / *End of period*	*Apr 2012* / *Sep 2012*	*Oct 2012* / *Dec 2012*	*Jan 2013* / *Sep 2013*	*Oct 2013* / *Sep 2014*	*Oct 2014* / *Sep 2015*	*Oct 2015* / *Sep 2016*	*Oct 2016* / *Sep 2017*	*Aggregate*
Our allowed revenues for transmission (2009/10)	13	6	21	28	30	31	33	163
Our allowed revenues for distribution (2009/10)	86	45	119	157	144	148	146	846
Our allowed revenues (2009/10)	99	51	140	186	174	180	180	1,009
Duration of period	6 mths	3 mths	9 mths	1 year	1 year	1 year	1 year	5.5 years

Source: CC calculations.

Implications of our findings for customers

43. We now set out our expectations as to the effect our provisional determination would have on customers. Our determination will set NIE's maximum allowed revenues for distribution and transmission use of system charges. It will not set directly the distribution and transmission tariffs that NIE charges to SONI and energy retailers, or any of the prices charged by energy retailers to customers. NIE's distribution and transmission tariffs are subject to separate approval by the UR. We have assumed that tariffs are adjusted pro rata to changes in allowed revenues.

44. We have used the UR's financial model to estimate the impact of our provisional determination on allowed revenues. We have also made allowances to deal with the effect of past under- or over-recoveries of revenue between April 2012 and September 2014.

45. The expected effect on customer tariffs is shown in Table 2. We do this in both real and nominal terms, expressed relative to RPI increases to 2013 and forecast RPI increases thereafter (actual allowed revenues will be adjusted for out-turn RPI inflation). In Table 3, we show the cumulative effect on NIE charges of actual and forecast changes.

TABLE 2 **Percentage annual increase in NIE's charges over period October 2012 to September 2017**

per cent

	Price changes already announced		*RPI forecast and implied price changes to be announced*		
Price increase at 1 October each year	*2012*	*2013*	*2014*	*2015*	*2016*
Real price change	1.7	–2.8	3.7	0.7	0.0
RPI increase (actual/latest OBR forecasts)	3.3	2.8	3.0	3.4	3.8
Nominal price increase	5.0	0	6.7	4.1	3.8

Source: CC analysis.

TABLE 3 **Cumulative percentage increase in NIE's real and nominal actual and forecast charges over period October 2012 to September 2017**

Cumulative percentage

	Actual 1 October		*Forecast 1 October*		
	2012	*2013*	*2014*	*2015*	*2016*
Real price change	1.7	–1.1	2.6	3.3	3.3
RPI increase	3.3	6.2	9.4	13.1	17.4
Nominal price increase	5.0	5.0	12.1	16.7	21.1

Source: CC analysis.

46. Our provisional determination will see an increase in charges from October 2014 onwards, with the size of the increase relative to RPI declining in 2015 and unchanged in 2016. The nominal price increases will depend on actual changes in the RPI. In real terms, as shown in Table 3, our determination allows a small cumulative increase in charges of 3.3 per cent relative to RPI over the whole of the RP5 period (ie from April 2012). In nominal terms, forecast RPI growth over the period means that charges are expected to increase by 21 per cent, corresponding to an increase of around 5 per cent in a typical customer's total electricity bill.

47. For a representative domestic customer the cumulative impact on charges over the whole determination period (comparing the forecast 2017 charges with those that applied in 2012) would be around £5 a year in real terms, and £32 a year in nominal terms.

48. The total allowed revenues in our determination may vary depending on whether NIE seeks, and the UR approves, allowances for additional investment projects for distribution network-load-related expenditure. Actual nominal customer charges will also vary depending on out-turn RPI figures.

49. A direct comparison of the tariff effects of our redetermination with the UR's determination, and with NIE's proposals, is complex. We consider that the most approp-

riate basis for comparison is the total allowed revenue (in real terms) standardized on the period 1 April 2012 to 30 September 2017. We estimate that our determination's aggregate allowed revenues over 5.5 years are £1,009 million, whereas the UR determination's aggregate allowed revenues over 5.5 years were £1,078 million. Therefore NIE's charges for distribution and transmission use of system are expected to be about 6.4 per cent lower under our redetermination than they might have been under the UR's RP5 determination.

Conclusions on the public interest

50. The approach we have adopted above is to consider for each aspect of the Price Control Conditions what designs will best serve the public interest and what level of cost allowances are appropriate. We also considered whether the overall effect of the modifications we have proposed can be expected to operate in the public interest when considered together, and with regard to all elements of the public interest test in the round.

51. Ultimately it is a matter of judgement to balance the various aspects of the public interest in light of the relevant evidence. As we consider that our provisional determination strikes an appropriate balance, we conclude that it will, overall, operate in the public interest.

Provisional determination

1. Introduction

The reference

1.1 The UR issued a Price Control Determination for NIE on 23 October 2012 in respect of NIE's Licences for transmission and distribution, together with proposed draft Licence modifications. On 20 November 2012, NIE responded with a letter rejecting the Licence modifications and suggested that a reference should be made to the CC. On 30 April 2013, the UR made a reference to the CC. The UR's notice of reference to the CC was published on our website on 30 April 2013 and is at Appendix 1.1 to this report. In accordance with Article 15(1) of the Electricity Order, the reference provided six months[1] for the CC to consider:

- whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest;
- whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences; and
- if so, whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the Conditions of each Licence.

1.2 The specific matters which the UR has required the CC to investigate are 'the Price Control Conditions'. This term is defined in Recital B to the reference and refers to

[1] On 20 August 2013, the UR extended the period for making the report to 29 April 2014.

Condition 42 and Annex 2 in each Licence which deal with the restrictions on the charges that may be made by NIE for the transmission and distribution of electricity.[2]

1.3 By way of background, paragraph 7 of Part I of each Licence (Grant and Terms of Licence) provide that the conditions in the Licence are subject to modification or amendment in accordance with their terms and/or with any lawful power of modification that may exist from time to time. The Electricity Order gives the UR the power to modify the conditions of a particular licence, but provides that the UR may not do so unless the licence holder consents.[3] The Licence holder (in this case NIE) is required to indicate whether it consents to any proposed licence modifications within a specified period of no less than 28 days, starting from the day the UR gives formal notice of the proposed modifications. If the licence holder does not consent (as NIE did not in this case), the proposed licence modifications do not come into effect.

1.4 Article 15 of the Electricity Order provides the power for the UR to make references to the CC. On receiving such a reference, the CC is required to report whether the matters specified in the reference operate against the public interest, and to determine whether any public interest detriment could be remedied by licence modifications. The decisions of the CC made on the reference are binding both on NIE and the UR.[4]

1.5 Accordingly, our task is to consider the questions that the UR referred to us, and we note that these relate to the Licences in their current form, ie not modified as proposed by the UR in its Price Control Determination for NIE on 23 October 2012.

[2] Annex 2 to each licence is the transmission and distribution charge restriction condition which caps the revenue NIE can earn from its levied distribution and transmission charges. Annex 2 is identical in each licence. Regulation 90(3) of the 2011 Regulations provides that Annex 2 to each licence shall be taken as relating to the activities authorized by both licences taken together.
[3] Electricity Order Article 14.
[4] Electricity Order Article 17.

1.6 This document and its appendices comprise our provisional determination on the questions which the UR required us to consider. Non-commercially-sensitive versions of written submissions from the main and third parties and a summary of hearings with third parties are published on our website[5] along with other relevant documents. We cross-refer to them where appropriate.

Our approach to the reference

1.7 Since NIE rejected the UR's Final Determination Notice, the UR's proposals for RP5 have fallen away. We are therefore required to consider whether the current Price Control Conditions will operate, or may be expected to operate, against the public interest. It is only if we answer that question in the affirmative that we are required to consider whether the effects adverse to the public interest can be remedied or prevented by licence modifications. The starting point for our work is therefore the current Licence.

1.8 In considering the reference questions, the differences between the UR and NIE, and between their respective proposals and submissions, have been helpful in informing our thinking. Those matters giving rise to disagreement between the regulator and the regulated company have been important—though by no means the only—factors in our investigation and have helped shape our provisional determinations. However, we have not confined ourselves to considering the UR's proposals in its determination, or NIE's objections to them, but with the current Licence conditions. In the interests of proportionality, we have concentrated on the current items that we expect could have the greatest effect on the price determination.

[5] www.competition-commission.org.uk/our-work/directory-of-all-inquiries/northern-ireland-electricity-price-determination/evidence.

1.9 Our assessment of the extensive evidence and analysis prepared by the UR, NIE and their consultants during the RP5 price control review has been an important element of our own work and materials submitted by the parties have often provided the basis for our further investigation.

1.10 We engaged consultant engineers, BPI, to advise us on NIE's capex proposals. We also engaged a consultancy, Pelicam Project Assurance, to help us investigate issues relating to the Enduring Solution Project and non-network capex (see paragraphs (10.28 to 10.60 and 10.115 to 10.181).

1.11 We also used the best data available to us, which meant that in some cases we used data that had been updated since the UR reached its determination.

1.12 Article 15(7) of the Electricity Order provides that, in determining whether any particular matter operates, or may be expected to operate, against the public interest, the CC must have regard to the matters as respects which duties are imposed on the UR by Article 12 of the Energy Order[6] or Article 9 of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 (SEM Order).[7] This means that, in making our determination, we are required to have regard to the duties of the UR as set out in paragraphs 2.40 to 2.52. This includes determining whether any particular matter operates or may be expected to operate against the public interest.[8]

1.13 In doing so, we have had regard to the UR's principal objective which, in accordance with Article 12 of the Energy Order, is the protection of the interests of consumers of electricity supplied by authorized suppliers, wherever appropriate by promoting

[6] SI 2003 No. 419 (N.I.6).
[7] These Articles apply in the alternative, such that Article 12 of the Energy Order does not apply in relation to the carrying out of functions of the UR to which Article 9 of the SEM Order applies (Article 13(1A) of the Energy Order). Given that Article 9 of the SEM Order relates to the UR's duties in giving effect to any decision of the Single Electricity Market Committee, which is not the subject of the reference, the relevant Article for the purposes of the CC's investigation is Article 12 of the Energy Order. Therefore, Article 9 of the SEM Order does not apply.
[8] Article 15(7) of the Electricity Order.

effective competition between those engaged in the relevant commercial activity associated with the generation, transmission, distribution or supply of electricity. The public interest scheme in its entirety, as set out in the Energy Order, the Electricity Order and the EU Electricity Directive,[9] is extensive. It provides, in addition to the principal objective of protecting the interests of consumers, for a detailed set of more specific objectives and further considerations to which the CC must have regard. At least some of these additional objectives and considerations may, properly understood and in terms of their substance, be part and parcel of an overall objective to further the interests of consumers.

1.14 Overall, in making our provisional determination we have sought to set a price control that gives sufficient weight to a range of considerations. For example, as well as the need to ensure fair consumer prices (where this includes both current and future consumers including business as well as domestic users), it would include consideration of the requirement to secure that all reasonable demands for electricity in Northern Ireland are met (see paragraph 2.46), as well as a level of service quality that ensures that supply interruptions are kept to a reasonable level—that is, in other words, to ensure that 'lights are kept on'. Therefore protecting the interests of consumers may not merely be a matter of keeping prices for consumers, or individual groups of consumers—some of which may be particularly vulnerable—as low as possible. NIE must be able to finance its activities to fulfil its obligations under the Licence, which means that these various objectives and considerations should be seen not just in the short term. The extent to which specific elements of the public interest test may be engaged will be determined by the relevant evidence. We believe that it would be difficult to demonstrate how the interests of consumers overall could be furthered if, for example, disproportionate weight were to be given to any of the various limbs of the public interest test, at the expense of one or more of

[9] OJ L211/55, 14 August 2009.

the others. Consumers should properly benefit from, for example, both fair prices and the satisfaction of all reasonable demands. We have taken care that no disproportionate weight is to be given to any of the various limbs of the public interest test, at the expense of one or more others. We have balanced and attached appropriate weight to specific public interest factors where the particular facts and evidence before us have given us reason to do so. The requirement to have regard to the duties of the UR does not mean that we would be required to follow the same approach that the UR has adopted or adopt the same methodologies.

1.15 In addition, we take account of other factors where relevant to the particular issue, which will include (among other considerations) the Northern Ireland Government's aspiration to have 40 per cent of electricity generated from renewable sources by 2020, and the need to facilitate a single electricity market in the island of Ireland. While the 40 per cent renewable target is not a statutory obligation as such, we note that it is nonetheless a relevant policy target to combat climate change. Both NIE and the UR have referred to it in various submissions to us.

2. Background

Introduction

2.1 In this section we describe:

- NIE's current business, its history, and its transmission and distribution Licences;
- developments in the electricity market in Northern Ireland;
- government energy policy;
- the UR and its duties;
- the process of price control reviews;
- NIE's network charges and how they compare with other UK electricity distribution companies; and
- NIE's consumer[10] base for electricity and issues relating to the interests of consumers.

NIE

NIE's current business

2.2 NIE is the owner of the electricity transmission network in Northern Ireland and the owner and operator of the distribution network.[11] Taken together, the transmission and distribution networks are used to convey electricity between generating stations, interconnectors (ie the lines and cables connecting the Northern Ireland transmission system to those in the Republic of Ireland and Scotland) and consumers' premises.[12]

2.3 NIE's transmission and distribution network contains several interconnected networks of overhead lines and underground cables which are used for the transfer of elec-

[10] We refer to consumers, or electricity customers, to identify domestic and industrial and commercial consumers of electricity. These consumers are not direct customers of NIE, rather their contracts will be with electricity suppliers. NIE's direct customers are electricity suppliers (principally through use of distribution system charges) and SONI (through transmission services charges), albeit that the charges to customers will be based on categories of final consumer and their consumption.
[11] Transmission is the bulk transfer of electrical energy, from generating power plants to electrical substations located near demand centres. Electricity is transmitted at very high voltages (110 kV or above) to minimize the energy lost when transported over long distances. When transmission lines reach substations which are located close to major load centres, the voltage is lowered so it can be sent through smaller power lines or cables. The distribution network carries electricity from the transmission system and delivers it through high-voltage and low-voltage networks of wood pole lines and cables to consumers' premises. Distribution lines and cables in Northern Ireland distribute electricity at voltages of 33 kV, 11 kV and 6.6 kV. (NIE Statement of Case, Annex 5.A.1.)
[12] NIE Statement of Case, Annex 1A.1, paragraph 4.1.

tricity to approximately 840,000 consumers via a number of substations. There are approximately 2,200 km (circuit length) of transmission system, 43,500 km of distribution system and 250 major substations throughout the NIE network.[13]

2.4 NIE derives its revenue principally through:

- use of distribution system charges levied on electricity suppliers; and
- transmission services charges levied on SONI—see paragraphs 2.27 to 2.30.[14]

2.5 These revenues are set out in more detail in Table 2.1. This shows that in the year to March 2013, about 65 per cent of NIE's income came from distribution charges. Of that 65 per cent, 56 per cent came from domestic consumers and 44 per cent from industrial and commercial users. The other 35 per cent of NIE's income came from Transmission charges paid by SONI Ltd (16 per cent), the Public Service Obligation (PSO)[15] (12 per cent) and other income (8 per cent).

TABLE 2.1 **NIE income, year ended 31 March 2013**

	£	%	%
Domestic	100,478,732	57	38
Extra high voltage	1,349,486	1	1
High voltage	11,615,291	7	4
Larger business low voltage	37,278,707	21	14
Small business	23,560,585	13	9
Unmetered Supplies	1,966,784	1	1
Distribution total	176,249,584	100	66
Transmission (charged to SONI)	41,621,570		16
PSO	31,765,000		12
Other income	16,060,000		6
Total	265,696,154		100

Source: NIE regulatory accounts and detailed breakdown of income provided by NIE.

[13] ibid, Annex 1A.1, paragraph 4.3. Further detail on the structure of the Northern Ireland electricity system and market is given in Appendix 2.1.
[14] NIE Statement of Case, Annex 1A.1, paragraph 4.4
[15] PSO charges relate to matters which benefit all electricity consumers in Northern Ireland. They arise from costs approved by the UR incurred by Power NI's power procurement and supply businesses, the Northern Ireland Sustainable Energy Programme, and NIE's costs associated with market opening and the Land Bank business. (NIE Statement of Case, Annex 1A.1, paragraph 5.17, fn 30.)

2.6 In addition to the maintenance and development of the transmission and distribution network, NIE told us that its other areas of transmission and distribution activities included:

- development of the network to accommodate the connection of renewable generation in accordance with the Government's renewable energy integration targets for 2020 (see paragraph 2.36);
- increasing interconnection transfer capacity between the electricity networks in Northern Ireland and the Republic of Ireland (see paragraph 2.34); and
- wider market services.[16]

2.7 NIE's transmission system is connected to that of the Republic of Ireland through 275 kV and 110 kV interconnectors and to that in Scotland via the Moyle Interconnector. NIE owns and maintains these transmission circuits within Northern Ireland. There are also plans to strengthen further the interconnection of the electricity networks of Northern Ireland and the Republic of Ireland via a 400 kV North–South interconnector. This is currently subject to a public inquiry.[17] The Moyle Interconnector is owned by Moyle Interconnector Limited (part of the Mutual Energy group of companies).

2.8 NIE told us that in its role as 'common service provider', it operated the market registration service and the market data service,[18] and acted as meter data provider to facilitate the operation of the Single Electricity Market (SEM—see paragraph 2.23) and the downstream retail market. NIE also told us that in support of this it had recently implemented a new IT system (the Enduring Solution project) to: provide full

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[16] NIE Statement of Case, Annex 1A.1, paragraph 4.2.
[17] ibid, Annex 1A.1, paragraph 4.6.
[18] These roles arise from NIE's licence condition 28. The purpose of the market registration service is to create a register of technical and other data as necessary to facilitate supply by a licensed supplier to premises connected to the total system and to provide information for settlement purposes. The market data service facilitates collection, processing and valuation of electricity flows at metered and unmetered premises. NIE also transfers such data as reasonably required and requested by licensed suppliers and SONI (as transmission system operator and Northern Ireland market operator). (NIE Statement of Case, Annex 1A.1, paragraph 5.17.)

business separation between NIE and Power NI's systems; allow for consumers to switch electricity supplier; and to accommodate potential future changes to market requirements.[19]

2.9 NIE is no longer involved in the generation of electricity, nor in the purchase and supply of electricity to customers. The overall structure of the electricity industry in Northern Ireland is set out in Appendix 2.1.

History of NIE and its current structure

2.10 NIE was incorporated on 25 October 1991 as a public limited company. In March 1992, it was granted Licences to transmit electricity and to act as a public electricity supplier. Conditions of its Licences regulated its activities in relation to: power procurement (including transmission system operation); electricity transmission and distribution; and electricity supply.

2.11 The generating operations of Northern Ireland Electricity Service (the legacy electricity public utility) were separated from NIE and sold to third parties in April 1992, removing electricity generation from the scope of NIE's regulated business activities.[20] NIE was floated on the London Stock Exchange in June 1993.[21]

2.12 NIE created a new holding company in 1998, Viridian Group PLC (Viridian Group), which acquired the entire issued share capital of NIE. NIE remained a public company but was delisted from the London Stock Exchange. The purpose of the reorganization was to separate NIE's regulated and unregulated business activities. Unregulated business operations (including IT, telecommunications, property, transport, insurance and financial services) were transferred to a separate subsidiary.

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[19] NIE Statement of Case, Annex 1A.1 paragraph 4.7.
[20] ibid, Annex 1A.1 paragraph 2.1-2.2.
[21] ibid, Annex 1A.1 paragraph 2.2.

NIE's affiliate, NIE Powerteam Limited (NIE Powerteam), was established as a vehicle for operational functions.[22] NIE said that NIE Powerteam provided its services exclusively to NIE and consequently nearly all of NIE Powerteam's revenues are generated from NIE.[23,24] NIE Powerteam has approximately 1,000 employees compared with approximately 300 employees for NIE. NIE Powerteam was made a direct subsidiary of NIE with effect from 1 October 2013.

2.13 In 2000, NIE separated its transmission system operation functions into a newly incorporated NIE subsidiary, SONI, to comply with EU legal requirements.[25] Also, in November 2007 (ahead of the launch of the SEM—see paragraph 2.23), NIE's regulated power procurement and supply businesses were transferred to a separately licensed Viridian Group subsidiary, NIE Energy Limited (now Power NI Energy Limited). NIE also agreed with the UR and the Department of Enterprise, Trade and Investment (DETI) to divest SONI in order to enhance further the independence of the transmission system operator in Northern Ireland[26,27] (see paragraph 2.27).

[22] The UR said that in 2005, Powerteam was split into two separate legal entities: Powerteam Electrical Services Ltd (PES) and NIE Powerteam Ltd. PES is a third party contractor that provides services on a commercial basis. There are limitations on the level of work that PES can carry out for Northern Ireland Electricity Limited. It is not a regulated entity.
[23] ibid, Annex 1A.1, paragraphs 2.3–2.4. NIE said that NIE Powerteam provided de minimis training services to third parties and occasionally NIE Powerteam provided assistance to other DNOs in restoring supplies after storm damage to their networks. We understand that revenues for these services are a very small proportion of Powerteam's total revenues.
[24] The UR said that Powerteam effectively operated as a department of NIE. It said that NIE used Powerteam for the majority of its subcontracted labour work on the network. Powerteam provided network services including metering, meter reading, overhead lines, customer operations and plant/technical support to NIE, as well as providing other support functions under managed service contracts. The UR told us that a number of business functions were shared across NIE and Powerteam. Examples included: telecommunications, IT, corporate service allocations, finance, technical, facilities management, HR and business improvement. The UR said that Powerteam was becoming a subsidiary to NIE (enacted from 1 October 2013) to ensure ring fencing from ESB going forward.
[25] NIE Statement of Case, Annex 1A.1, paragraph 2.5.
[26] In August 2008, NIE and EirGrid plc (the independent transmission system operator in the Republic of Ireland) reached conditional agreement for the sale of SONI, and in March 2009 SONI was sold to EirGrid plc.
[27] NIE Statement of Case, Annex 1A.1 paragraph 2.7.

2.14 In December 2006, Viridian Group was acquired by Arcapita Bank B.S.C. NIE told us that this acquisition had little impact on it, as it remained as a subsidiary of Viridian Group, which then was reregistered as a private limited company.[28]

2.15 In July 2010, ESB[29] and Viridian Group reached conditional agreement for the sale of NIE to ESB. NIE was acquired by an ESB subsidiary, ESBNI, in December 2010. ESBNI also acquired NIE Powerteam, Powerteam Electrical Services (UK) Limited and Capital Pensions Management Limited[30] from Viridian Group.[31]

2.16 NIE said that it was subject to strict ring-fencing obligations pursuant to its Licences which separated it from the rest of the ESB group.[32] In Appendix 2.2, we discuss ESB and its relationship to NIE.

2.17 Some of NIE's recent financial results are detailed in Table 2.1. An adjustment is made to the statutory operating profit to reflect the fact that charges in subsequent years are adjusted if there is over- or under-recovery of revenues relative to entitlements in particular years. In its annual reports, NIE explains that it considers the adjusted, pro-forma operating profit figures to be more meaningful. The profit figures in Table 2.2 include some discontinued operations (eg the sale of SONI). We note that NIE has not paid dividends to shareholders since 2010.

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[28] ibid, Annex 1A.1, paragraph 2.6.
[29] ESB is owned by the Irish Government (95 per cent) and by employees (5 per cent). It is also one of the electricity suppliers in the island of Ireland.
[30] NIE said that Powerteam Electrical Services (UK) Limited designed, supplied and constructed high-voltage electrical infrastructure solutions for third party utility and private operators throughout GB and Ireland. Capital Pensions Management Limited is effectively an in-house team of three staff managing NIE's pension scheme.
[31] NIE Statement of Case, Annex 1A.1, paragraph 2.8.
[32] For example, licence condition 14 contains a ring-fencing obligation which prohibits the core regulated business activities of NIE being held or carried on by any of its affiliates. (NIE Statement of Case, Annex 1.A.1, paragraph 5.17.)

TABLE 2.2 **NIE's selected financial results for the last five years**

£ million

Financial accounts	*Group statutory operating profit*	*Deduct/add back regulatory correction factor*	*Group pro-forma operating profit*	*Capital expenditure*	*Operational expenditure*	*Dividends declared and paid*
31/3/2008	130.8*	–17.3	113.5	120.0	81	Ordinary: 94.4, Preference: 2.1
31/3/2009	116.8†	–2.8	114	104.6	86.2	Ordinary: 110.6
31/3/2010	114.6	–5.8	108.8	95.1	90	Ordinary: 55
31/3/2011	68.8	29.6	98.4	109.1	112.8	Ordinary: none
31/3/2012	107	–14.4	92.6	130.6	87.6	Ordinary: none

Source: NIE Annual Report and Accounts 2009–2012. NIE Statement of Case, Annex 1A.1, paragraph 4.11.

*Operating profit from continuing operations £16.8 million.
†Operating profit from continuing operations £84 million.

NIE's transmission and distribution Licences

2.18 The electricity market in Northern Ireland is a regulated market with participants licensed to engage in activities. NIE is subject to economic and customer service regulation by the UR—see paragraphs 2.40 to 2.57.

2.19 NIE's original Licence dated 31 March 1992, granted under the Electricity Order, was to 'transmit electricity for the purpose of giving a supply to any premises or enabling a supply to be so given in the authorised transmission area'. The authorized area under the Licence is Northern Ireland.[33] In accordance with and pursuant to Regulation 90(1) the Gas and Electricity (Internal Markets) Regulations (Northern Ireland) 2011 (2011 Regulations), as amended from 15 April 2011, NIE's original Licence has had effect as if it were two separate Licences, called the successor transmission Licence (granted under Article 10(1)(b) of the Electricity Order) and the successor distribution Licence (granted under Article 10(1)(bb) of the Electricity Order). The UR published the two successor Licences, in each case modified in accordance with Regulation 90(5) of the 2011 Regulations, on 11 March 2013. Many, but not all, conditions are common to both Licences. Part II of each Licence sets out the Licence conditions. Some conditions cover the preparation and exchange of

[33] Paragraph 1 of Schedule 1 of the Licences.

information, such as Condition 2 which requires NIE to prepare regulatory accounts in respect of the transmission and distribution businesses each financial year and to have them audited (with the auditors' report being provided to the UR) and Condition 8 which requires NIE to provide to the UR such information as the UR may require to perform its statutory functions. Other conditions deal with financial matters, including the requirement in Condition 9A for NIE to take all appropriate steps to ensure that it obtains and maintains an investment grade credit rating.

2.20 Condition 42 and Annex 2 contain the charge restriction applicable to NIE's transmission and distribution business. These are identical in both the successor transmission Licence and the successor distribution Licence and are referred to as the Price Control Conditions in the reference.[34] Paragraph 7.1 of Annex 2 provides that the transmission and distribution charge restriction conditions apply so long as the Licences continue to be in force.[35] The Price Control Conditions cease to have effect (in whole or in part, as the case may be) if NIE serves a disapplication notice on the UR, which it may do in certain circumstances, and following a process, set out in the conditions.[36]

2.21 NIE is subject to a number of statutory duties as an electricity distributor and licensed participant in transmission. Its principal general duties are contained in Article 12 of the Electricity Order which provides that:

> 12.(1) It shall be the duty of an electricity distributor to—

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[34] Regulation 90(3) of the 2011 Regulations provides that Annex 2 to each licence shall be taken as relating to the activities authorized by both licences taken together.

[35] Under paragraph 1 of Part I, each licence continues in force unless revoked in accordance with the terms specified in Schedule 2 (Terms as to Revocation) or determined by not less than 25 years' notice in writing given by DETI.

[36] Paragraphs 7.1–7.6 of Annex 2 contain details on the disapplication process. A disapplication request must specify the transmission and distribution charge restriction conditions (or any parts thereof) to which it relates. If the UR agrees to the request, such conditions will be disapplied, subject to certain timelines being followed. If the UR does not agree, it may either make a reference to the CC which will, as part of its investigation, decide whether or not the transmission and distribution charge restriction conditions specified in the disapplication request operate against the public interest. If the CC decides that such conditions do not operate against the public interest, NIE may terminate these conditions by giving notice to the UR. Alternatively, and in the absence of a reference to the CC, NIE may deliver written notice to the UR to terminate the application of the specified conditions.

(a) develop and maintain an efficient, coordinated and economical system of electricity distribution which has the long-term ability to meet reasonable demands for the distribution of electricity; and

(b) facilitate competition in the supply and generation of electricity.

(2) It shall be the duty of the holder of a licence under Article 10(1)(b), as appropriate having regard to the activities authorised by the licence, to—

(a) take such steps as are reasonably practicable to —

(i) ensure the development and maintenance of an efficient, coordinated and economical system of electricity transmission which has the long-term ability to meet reasonable demands for the transmission of electricity; and

(ii) contribute to security of supply through adequate transmission capacity and system reliability; and

(b) facilitate competition in the supply and generation of electricity.

Developments in the electricity market in Northern Ireland

2.22 Prior to privatization, Northern Ireland Electricity Service was the public utility responsible for electricity generation, transmission (including system operation), distribution and supply throughout Northern Ireland. The first stage in the privatization process was the sale in 1992 of NIE's generation capacity to three separate trade buyers who purchased power station assets (NIE was the sole customer through its then power procurement business). Competition for supply to all large electricity customers was introduced in 1999 and then in 2005 competition for supply to all non-residential customers was introduced.[37]

[37] NIE Statement of Case, Annex 1A.1, paragraph 3.1.

2.23 An important structural and regulatory change in the Northern Ireland electricity market occurred in November 2007 with the implementation of the SEM in the island of Ireland. The SEM was designed to promote the establishment and operation of a single competitive wholesale electricity market in Northern Ireland and the Republic of Ireland. It was implemented in Northern Ireland by means of the SEM Order. The SEM consists of a gross mandatory pool market, into which all electricity supplied by generators of more than 100 MW capacity in (or importing into) the island of Ireland must be sold, and from which all wholesale electricity for consumption in or to be exported from the island of Ireland must be purchased.[38]

2.24 On 1 November 2007, the Electricity Regulations (Northern Ireland) 2007 (2007 Regulations) came into force. The 2007 Regulations implemented Directive 2003/54/EC and sought to achieve legal and functional separation of transmission and distribution system activities from those of supply and generation, and to ensure greater market freedom for consumers to purchase electricity from their supplier of choice.[39]

2.25 A further structural change in the Northern Ireland market has been driven by the EU Third Energy Package (IME3). IME3 has been (partially) implemented in Northern Ireland by 2011 Regulations among other legal instruments. The most relevant of the IME3 objectives to NIE's regulated activities are the unbundling of transmission and distribution networks and the certification of all transmission system operators.[40]

2.26 The 2011 Regulations introduced certain measures in Northern Ireland to ensure compliance with the unbundling requirements of IME3. Part III of the 2011 Regulations sets out the new ownership (or unbundling) regime for transmission

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[38] ibid, Annex 1A.1, paragraphs 3.3–3.5 .
[39] ibid, Annex 1A.1, paragraphs 3.10–3.12.
[40] ibid, Annex 1A.1, paragraph 3.19.

networks, implementing full separation of electricity transmission from production and supply and sets down procedures for the certification of transmission operators. Part V of the 2011 Regulations introduced new (and transitional) powers for the UR unilaterally to amend electricity licences to ensure that licensed activities comply with the requirements of IME3.[41]

2.27 As a result of the unbundling requirement (paragraph 2.26), SONI (rather than NIE) will be certified as the transmission system operator for Northern Ireland.[42] It was purchased by EirGrid—the equivalent system operator in the Republic of Ireland which is based in Dublin. SONI's income is derived from a 'system support service tariff' which is approved by the regulator.[43] SONI has two licensed activities: one for its system operator activities where the current price control concludes in 2015 and a separate Licence for its market operator activities which has a separate price control and commences on 1 October 2013. Its all-Ireland market operator activities are regulated jointly by the UR and CER.[44]

2.28 NIE is currently responsible, in conjunction with SONI, for planning, developing and maintaining the transmission network.[45] SONI said that it expected to take over all planning functions by April 2014, and it expected that it would then review NIE's investment plans. It acknowledged that some decisions on investment would have already been made by then in relation to the RP5 current price control period. [46]

2.29 The UR told us that while NIE was presently responsible for planning whether, where, when and how the transmission system should be developed (eg by way of upgrades to capacity, the construction of new lines to meet forecast demand growth,

[41] ibid, Annex 1A.1, paragraph 3.13.
[42] ibid, Annex 1A.1, paragraph 3.19.
[43] SONI hearing summary, paragraphs 1 & 2.
[44] ibid, paragraph 3.
[45] NIE Statement of Case, Annex 1A.1, paragraph 4.1.
[46] SONI hearing summary, paragraph 8.

etc), in future at least some or all of these planning decisions will be undertaken by SONI. It said that what this meant in practice was not yet fully developed. However, there were certain tasks, activities and decisions in relation to investment planning that were presently undertaken by NIE and would during the course of RP5 be undertaken by SONI. It said that this change in responsibilities would inevitably have an impact on matters relating to capital expenditure. While responsibility for physically developing the system would remain with NIE, so that it would therefore continue to incur capital expenditure, the primary decision-making role in relation to system development would pass to SONI. The UR said that this introduced an additional level of uncertainty in relation to the need for capital expenditure by NIE during RP5.

2.30 NIE and SONI management told us that they had agreed the principles of how functions should be arranged to give effect to the transfer of transmission investment planning to SONI. A summary of some of the relevant proposed principles is set out in Appendix 2.3. They said that these principles would be translated into a Transmission Interface Agreement (TIA) between SONI and NIE, and would be subject to regulatory approval. They intended to submit the draft TIA by 10 January 2014 to the UR which would then consult on their proposed decision.

2.31 Given the uncertainty regarding the arrangements to be concluded, we have not at this stage made explicit allowance in our determination for the transfer of responsibilities for planning to SONI.

Government energy policy

2.32 In Northern Ireland, energy policy is the responsibility of the Department of Enterprise, Trade and Investment (DETI). The Energy (Northern Ireland) Order 2003 (Article 12) sets out the principal objective and duties of DETI and the Northern Ireland Authority for Utility Regulation in relation to the electricity sector. The principal objective is to protect the interests of consumers of electricity supplied by authorized suppliers.

2.33 The key document for energy policy is the Strategic Energy Framework (SEF), which was published by the Northern Ireland Executive in 2010. The SEF set out energy policy up to 2020. The document sets out key priorities to guide market participants, encourage investment in both renewable energy and the provision of new infrastructure (including electricity infrastructure). DETI told us that the aim was to improve security and diversity of energy supply and support economic activity while reducing carbon emissions.[47]

2.34 The SEF references the most significant policy intervention in recent times as being the creation of the SEM in Northern Ireland and the Republic of Ireland. As a result of developments at a European level, the SEM is now subject to further change to meet the requirements of the new target model to facilitate greater integration across the EU. DETI said that the Northern Ireland Executive believed that the key to growing the electricity market was a robust and stable electricity transmission system and that this was critical to a modern economy. It said that a robust, modern electricity grid was also an important requirement given the EU targets associated with decarbonization and regulatory and technical challenges of integrating renewables on to the grid.

2.35 Challenging renewables targets are set in the SEF for Northern Ireland. Under specific action (number 37) of the SEF DETI is tasked with ensuring cooperation between the UR, NIE and SONI to deliver the required electricity grid infrastructure.

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[47] DETI submission.

2.36 The key target is that by 2020, 40 per cent of Northern Ireland's electricity consumption will come from renewable sources. A consequence of increased renewable generation is that the electricity transmission and distribution networks will be likely to need to be updated and reinforced to cope with the incorporation of often small-scale generation (such as small wind farms) in dispersed areas. The quantities of generated electricity to be carried at points in the network, and the directions of flow, can change substantially. Furthermore, the quantity, location and timing of these investments is uncertain.

2.37 Around 2009, NIE estimated that the scale of investment required to achieve both the renewables target set out in the SEF and the regular maintenance and development of the grid up to 2020 is in the region of £1 billion. The Northern Ireland Renewables Industry Group (NIRIG) told us that a lower level of around £360 million was required to fund the additional investment attributable to renewables.[48]

2.38 NIE told us that a more recent detailed NIE/SONI/Eirgrid study (Renewable Integration Development Project (RIDP)) had identified a joint Northern Ireland/Republic of Ireland transmission development proposal for the North and West of Northern Ireland that would imply a joint (Northern Ireland and Republic of Ireland) investment level of less than £500 million. However, NIE said that it would be wrong to assume that this scheme, in its entirety, would necessarily be required to meet government targets.

2.39 In addition to onshore wind generation in the North and West of the island, which was the particular focus of RIDP, NIE told us there was additional planned offshore wind farms on the east coast to contribute to meeting government targets. NIE said that whilst this might reduce the RIDP costs, there would also be costs associated with

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[48] See summary of hearing with NIRIG.

transmission reinforcement in the east of the province associated with this new off-shore generation. NIE said that it had not as yet received an application from the off-shore developers and could not therefore confirm the level of required transmission reinforcement.

The UR and its duties

2.40 The UR is an independent statutory body corporate with its board appointed by the Northern Ireland Executive. It is a non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries. Previously known as Ofreg, its statutory duties are set out in the Energy Order and the Water and Sewerage Services (Northern Ireland) Order 2006.

2.41 The objectives of electricity regulation and the duties of the UR are set out in the Energy Order as amended, in particular by the 2011[49] Regulations (which transposed certain requirements of the EU Third Energy package into law in Northern Ireland). The UR's statutory functions as set out in the Electricity Order[50] include:[51]

- granting licences for the generation, transmission, distribution and supply of electricity in Northern Ireland (Articles 10, 10A, 10AA and 11);
- certifying, monitoring and reviewing transmission licensees as independent operators pursuant to IME3 (Article 10B to 10K);
- the power to modify electricity licence conditions (Articles 14 to 18 as discussed in more detail below); and
- a general obligation to keep under review and collect information in respect of activities connected with the generation, transmission, distribution and supply of electricity in Northern Ireland.

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[49] SI 2011, No. 155.
[50] SI 2003, No. 419 (NI.6).
[51] NIE Statement of Case, Annex 1A.1, paragraph 5.6.

2.42 Generally, licences for the generation, transmission, distribution or supply of electricity in Northern Ireland are granted under Article 10 the Electricity Order.[52] The Electricity Order and the conditions of the licences granted under that Order are the principal means by which transmission and distribution of electricity in Northern Ireland is regulated.

2.43 This is supplemented, most notably in respect of the functions and duties of the UR and licensees respectively, by the Energy Order. Both the Electricity Order and the Energy Order have been amended by the SEM Order and the 2011 Regulations in order to achieve the objectives of market integration within the island of Ireland and to comply with wider market liberalization pursuant to IME3.[53]

2.44 The UR said that the details of and relationship between its various duties and objectives was somewhat complex, but at its core was a simple principal objective: to protect the interests of consumers. It said that in pursuing that objective, it was required to have regard, among other things, to the need to secure that all reasonable demands in Northern Ireland or the Republic of Ireland for electricity were met and the need to secure that licence holders were able to finance their activities.[54]

2.45 Specifically, the principal objective of the UR in carrying out its electricity-related functions as provided by the Energy Order is:

> to protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities

[52] SI 2003, No. 419 (N.I.6).
[53] NIE Statement of Case, Annex 1A.1, paragraphs 5.2–5.3.
[54] UR Statement of Case, paragraph 6.

connected with, the generation, transmission, distribution or supply of electricity. [55]

2.46 Article 12(2) requires UR to perform its functions:

> … in the manner which it considers is best calculated to further the principal objective, having regard to:
>
> (a) the need to secure that all reasonable demands in NI or RoI for electricity are met;
>
> (b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or this Order.

2.47 In addition, in performing the duties set out in Article 12(1), 12(1A) and 12(2), the UR must have regard to the need to protect the interests of:

- individuals who are disabled or chronically sick;
- individuals of pensionable age;
- individuals with low incomes; and
- individuals residing in rural areas.[56]

2.48 The above list is not exhaustive. The UR may also, when carrying out its electricity functions, have regard to the interests of consumers in relation to gas, water or sewage services.[57]

2.49 The interests of consumers include their interests in the fulfilment by the UR of the objectives set out in Article 36(a) to (h) of Directive 2009/72/EC of the European

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[55] UR website.
[56] Article 12(3) of the Energy Order.
[57] ibid.

Parliament and of the Council of 13 July 2009[58] (the Electricity Directive).[59] These include: promoting a competitive, secure and environmentally sustainable internal market in electricity; developing competitive and properly functioning regional markets; ensuring that customers benefit through the efficient functioning of their national market; eliminating restrictions on trade in electricity between member states; helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented; promoting energy efficiency as well as the integration of large- and small-scale production of electricity from renewable energy sources and distributed generation in both transmission and distribution networks; facilitating access to the network for new generation capacity, in particular removing barriers that could prevent access for new market entrants and of electricity from renewable energy sources; ensuring that system operators and system users are granted appropriate incentives to increase efficiencies in system performance and foster market integration; helping to achieve high standards of universal and public service in electricity supply and contributing to the protection of vulnerable customers.[60] Article 36 of the Electricity Directive is set out in full in Appendix 2.4.

2.50 Subject to the duties set out in Article 12(2), the UR is required (Article 12(5) of the Electricity Order) to carry out its electricity functions in a manner it considers best calculated to:

- promote the efficient use of electricity and efficiency and economy by licensees;
- protect the public from dangers arising from the generation, transmission, distribution or supply of electricity;
- secure a diverse, viable and environmentally sustainable long-term energy supply;

[58] OJ L211/55, 14 August 2009.
[59] Article 12(1A) of the Energy Order.
[60] ibid.

- promote research into, and the development and use of, new techniques by licensees; and
- 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.

2.51 Additionally, in carrying out those functions, the UR must have regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity.[61]

2.52 The UR said that it sought to strike a balance in terms of these objectives, acknowledging that these could be in conflict. It said that it would seek to weigh up the balance of the objectives depending on the circumstances, and the balance was not always the same. It said that the principal objective was to protect consumers, but this was not just a question of obtaining the lowest price possible. It said that a fair amount of discretion and judgement was left to the regulator. It told us that some key indicators were relevant, for example the 40 per cent renewable target in the strategic energy framework. The SEF also referred to fuel poverty and industrial competitiveness. It also noted mandatory requirements, particularly on health and safety legislation. It said that where the legislation and policy was non-prescriptive, inevitably different decision-makers could strike different balances.

Price control reviews

2.53 There are no express provisions in either of the Electricity Order, the Energy Order or the Licences which provide for review of the charge restriction conditions in Condition 42 and Annex 2. However, in order to fulfil its statutory duties, the UR is required to keep under review whether NIE's Licence obligation continues to be apt to attain the

[61] ibid.

UR's statutory objectives and, in practice, this requires the UR periodically to review NIE's price controls. Indeed, in setting an individual price control, the UR generally indicates how long it is expected to apply, and, by implication, when it is scheduled to be subject to periodic review.

2.54 The UR has controlled charges for transmission and distribution by setting the revenues that NIE is allowed to raise during the following price control period. The UR said that the revenue it allowed enabled the company to recover its operating costs, depreciation and a reasonable return on investment. These revenues were collected from customers and generators through charges for use of the transmission and distribution systems.[62] The price control determination set these allowed revenues and proposed amendments to NIE's Licence to implement this.[63]

2.55 Since privatization, price controls have been applied for four five-year regulatory periods:[64]

- 1 April 1992 to 31 March 1997 (RP1). The price control which applied during RP1 was notified to NIE by DETI.
- 1 April 1997 to 31 March 2002 (RP2). In RP2 the UR and NIE failed to reach agreement on the final proposal for the price control, resulting in a reference to the then Monopolies and Mergers Commission (MMC). Following NIE's application for judicial review of the UR's decision not to give effect to the MMC's conclusions, which was successful before the Northern Ireland Court of Appeal, RP2 was settled two years later, by the UR's acceptance that NIE should set its charges by reference to the revenue allowance provided for by the MMC.
- 1 April 2002 to 31 March 2007 (RP3). The UR proposed, and NIE agreed, Licence modifications to implement the RP3 price control.

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[62] UR RP5 Final Determination, paragraph 2.14.
[63] NIE Statement of Case, Annex 1A.1, paragraph 5.30.
[64] ibid, Annex 1A.1, paragraphs 5.31–5.35.

- 1 April 2007 to 31 March 2012 (RP4). The agreed Licence modifications to implement the RP4 price control were made by the UR in December 2006.

2.56 The details of the RP4 price control conditions are outlined in more detail in paragraphs 3.8 to 3.41.

2.57 In addition to price controls, the UR also sets guaranteed and overall standards for services provided to consumers (eg the timely restoration of consumers' supplies following an interruption and prescribed times for responding to voltage complaints) by NIE.

2.58 The RP5 price control review process formally commenced in July 2010 with the UR publishing its 'Strategy Paper for the RP5 price control' setting out its proposed approach to the price control for consultation.

2.59 On 6 October 2011, the UR announced a six-month delay in the implementation of the RP5 price control. Although there is disagreement between the UR and NIE as to the status of the RP4 price control after 31 March 2012, NIE said that the UR purported to extend the RP4 price control for an interim period from 1 April 2012 to 30 September 2012, and then for a further period to 31 December 2012.

2.60 The RP5 draft determination was published on 19 April 2012 for consultation. Further detail, including the RP5 Capex 'Fund 3' criteria and incentive mechanisms consultation, and the capitalization practice draft determination were published at the end of August 2012. NIE told us that it had concerns with the RP5 process, and that it had written to the UR in 2011 and 2012 urging improved transparency and engagement.[65]

2.61 The Final Determination was issued on 23 October 2012, with a Licence modification notice and a draft modified Licence. NIE wrote to the UR on 20 November 2012 stating that it was unable to accept the terms of the Final Determination. This rejection led to the reference to us.

2.62 NIE told us that it had been compelled to reject the Final Determination because it would allow insufficient revenues to finance the activities which were necessary to enable it, in the short term, to provide a safe and reliable electricity transmission and distribution service to today's electricity customers, and in the longer term, to invest in the maintenance and development of the skills and assets required to provide such a service to future electricity customers.

2.63 It said that the UR's proposed price control would therefore leave NIE unable adequately to finance its regulated functions and would not serve the interests of electricity customers.[66] It identified five key alleged deficiencies it saw in the Final Determination:[67]

- The structure of the proposed price control departed from established principles of incentive-based regulation in favour of a system of regulation by micro-management and ex-post revision.
- The proposed price control provided insufficient allowed revenues to meet the needs of NIE's Business.
- The proposed arrangements for regulating network capex incorporated a rigid investment plan that would unduly constrain many of NIE's network investment

[65] NIE Statement of Case, Annex 1.A.1, paragraph 6.3.
[66] ibid, Chapter 1, paragraph 2.1.
[67] ibid, Chapter 1, paragraph 2.2.

decisions. Other parts of the capex arrangements involved an ex-post review of operational decisions and/or a requirement to agree, ex ante, changes to capex plans. This exposed NIE to an unacceptable risk of ex-post clawbacks.

- These deficiencies would result in adverse consequences for customers because:
  - they risked under-investment in NIE's network with consequential reductions in network resilience and performance; and
  - they substantially diminished incentives to innovate and achieve new sources of efficiency or improvements in the delivery of services to customers.
- NIE would be compelled to expend more than the price control proposals envisaged, with resultant unfair detriment to NIE's investors, and detriment to NIE's financial position and credit rating.

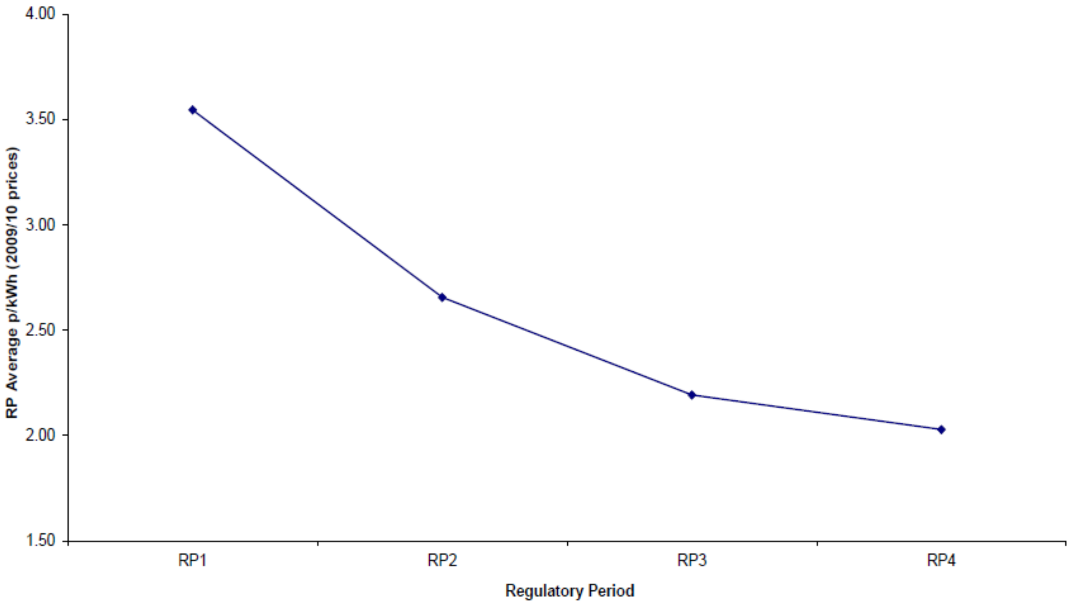
2.64 In Appendix 2.5 we summarize at high level the UR's final determination for RP5, with its reasoning for its proposals as set out in the determination document. It also describes the arrangements that have been in place following the initial expiry date of RP4.

Network charges

2.65 NIE's average use of system charges over the first four price control periods are shown in Figure 2.1.

FIGURE 2.1

NIE's network charges



Source: Figure 2.2 from NIE Statement of Case, p9.

2.66 NIE told us that there had been a 43 per cent reduction in real network charges since RP1, which it said reflected the efficiencies it had achieved over that time (for example, that staff numbers had fallen from 3,000 at privatization to 1,300 (including NIE and Powerteam).[68]

2.67 Table 2.3 gives an overview of NIE's distribution use of system charges and how they relate to the charges of some other UK electricity distribution companies. While we do not expect that charges will be the same for different distribution companies (for example, their costs will vary with the circumstances and proportionate size of their networks), relative charges do provide a point of reference which can be informative as a part of the assessment when considering whether charges are at a level consistent with the public interest.

[68] ibid, paragraphs 1.8–1.9.

2.68 The figures in Table 2.3 are annual distribution charges excluding VAT for each illustrative supply.[69]

2.69 There are some differences in the scope of distribution use of system charges which are relevant to the interpretation of Table 2.3:

- In addition to its distribution use of system charges for the North of Scotland, SHEPD receives a special subsidy from all GB customers, collected through National Grid. This subsidy has existed in some form since before privatization and was intended to mitigate high distribution costs in the North of Scotland.
- NIE's distribution use of system charges include charges for metering and data management services (in support of market opening), including management of prepayment meters, the equivalent of which is managed and charged for separately in Scotland, England and Wales. This adds to NIE's charges reported in Table 2.3.
- On the other hand, Scottish distribution use of system charges include the costs of using 132 kV/33 kV transformers (which are part of the transmission network but recharged to the distribution company), whereas NIE told us that its 110 kV/33 kV costs were seen as transmission costs charged to SONI (and so not included in the charges quoted in Table 2.3). In addition to this, in England and Wales, distribution use of system charges also include the costs of using the 132 kV system and transmission/132 kV transformers.

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[69] In order to give a readable description of NIE's distribution use of system tariffs, we use a set of illustrative notional customers, defined as follows:

- A domestic customer with a consumption of 2,000 kWh a year and a prepayment meter. This is a lower than average level of consumption, but is compatible with running a modern home (with little waste and no use of electricity for heating).
- A domestic customer with a consumption of 2,000 kWh a year and a credit meter.
- A domestic customer with a consumption of 4,000 kWh a year and a credit meter. This is an average amount of consumption for a household without electric heading (both in Northern Ireland or elsewhere in the UK).
- A domestic customer with a consumption of 8,000 kWh a year and a credit meter. This might be a large house in which the occupants do not give much thought to energy conservation.
- A small business customer taking 8,000 kWh a year. This corresponds, for example, to 200 watts of background load (server, fridge, etc) plus 2,500 watts 50 hours a week (lighting and computers for something like ten desks or a shop).
- A business supply of 150 kVA at 400 volts (not near the substation), consuming an average of 100 kW uncorrelated with time of day, week or year, and no reactive power.
- A business supply of 1,500 kVA at 11,000 volts (not near the primary substation), consuming an average of 1,000 kW uncorrelated with time of day, week or year, and no reactive power.
- A highway authority with 50 sets of traffic lights each taking 200 watts, and 2,000 street lights each taking 70 watts and operating at night (11 hours a day on average).

TABLE 2.3 **Distribution use of system charges**

	NIE 2012/13	North Scotland 2013/14	South Scotland 2013/14	South-west England 2013/14	London 2013/14
					£/year
Prepay 2,000 kWh	93	105	64	82	55
Domestic 2,000 kWh	83	105	64	82	55
Domestic 4,000 kWh	124	186	111	149	95
Domestic 8,000 kWh	207	347	206	283	176
Small business 8,000 kW	237	297	185	227	120
Business 150 kVA	11,603	20,831	11,894	15,960	9,163
Business 1,500 kVA	57,135	164,955	89,776	117,018	70,349
Highway authority 150 kW	10,964	18,337	11,992	22,030	10,075

Source: CC calculations.

2.70 The electricity distribution company serving the North of Scotland, SHEPD (part of the SSE plc group), has a distribution network which is quite similar to NIE's. Both NIE and SHEPD have very long overhead networks compared with other UK regional distribution networks. For NIE, the average overhead distribution network (excluding 132 kV) per customer is 36 metres compared with 36.7 metres for SHEPD. In comparison, the numbers are 9.8 metres for the South of Scotland, 17.6 metres for the South-West of England, and very little in London.[70]

2.71 It can be seen that relative to north Scotland, except for one category, NIE charges are lower than for SHEPD. Relative to the other DNOs, results are more mixed. They are higher than for London, other than for large business customers. In fact, larger business customers tend to face lower distribution charges in Northern Ireland (these comparisons are only for use of the distribution system, not the total cost of power).

Consumers

2.72 The NIE transmission and distribution network serves around 840,000 electricity customers. Of these, nearly 780,000 are domestic customers. Nearly 50,000 are small businesses which are billed quarterly. Around 10,000 are larger customers

[70] The figures underlying these calculations are taken from public sources. We acknowledge that they refer to different periods (between 2008 and 2012). However, it seems unlikely that they will change very fast.

metered half-hourly on MV <70 kVA or MV and about 400 are the largest customers on half-hourly metered HV or EHV.

Domestic consumers

2.73 In July 2013 the average domestic consumer in Northern Ireland had an annual domestic electricity bill (which includes transmission and distribution costs) of around £595, up from £505 in October 2012 (a rise of 17.8 per cent). In November 2007, electricity bills for domestic consumers averaged £385 a year. Between November 2007 and July 2013 electricity bills for domestic consumers in Northern Ireland rose by some 61 per cent. Average annual bills for an illustrative domestic customer from 2007 to 2013 are shown in Table 2.4.[71]

TABLE 2.4 **Power NI average annual bill for customer using 3,300 kWh of electricity on the standard tariff with postal bills paying by cash or cheque**

£

	Nov 2007	*July 2008*	*Oct 2008*	*Jan 2009*	*Oct 2009*	*Oct 2010*	*Oct 2011*	*Oct 2012*	*July 2013*
Cost (£)	385	439	585	522	496	496	588	505	595
% change	3.9	14	33.3	–10.8	–5	0	18.6	–14.1	17.8

Source: CCNI slides from hearing on 8 July.

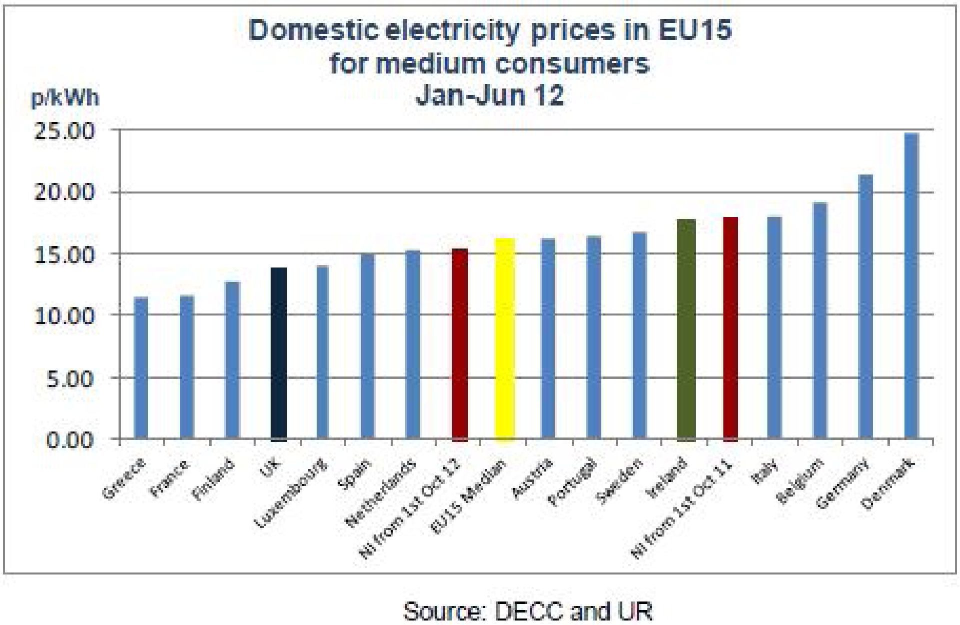
2.74 According to Power NI as at July 2013 following a 17.8 per cent rise in electricity charges, Northern Ireland domestic electricity prices were about 5 per cent higher than in comparable GB regions and about 8.7 per cent higher than the GB average. The long-run average difference in electricity prices between January 2009 and July 2013 is for Northern Ireland to be 10 per cent higher than GB. [72]

2.75 However, turning to international comparisons, between January and June 2012 the price that domestic consumers in Northern Ireland paid for their electricity was slightly below the median average for the 15 countries in the EU.

[71] This comparison uses an estimated consumption of 3,300 kWh of electricity. We understand that the average consumption of electricity by domestic consumers now exceeds this figure.
[72] www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

FIGURE 2.2

Domestic electricity prices by country



Source: UR March 2013: NI Electricity Prices Data and Comparisons Information paper.

Consumers' electricity bills

2.76 In 2012/13, transmission and distribution charges made up around 25 per cent of domestic electricity bills. NIE told us that in the case of domestic customers, network charges typically made up around 20 per cent of the final bill, generation costs 64 per cent, and other allocations around 16 per cent.[73] CCNI, however, told us that network charges made up 28 per cent of the average domestic bill (£167 a year) compared with 58 per cent for generation. The UR's Final Determination (paragraph 16.8) noted that network charges made up in the region of 20 per cent of domestic electricity bills. The UR's briefing paper on Power NI's 2013 Tariff Review background paper[74] showed that domestic customers' electricity bills were made up of the components shown in Figure 2.3.

[73] NIE Statement of Case, Annex 5A.1, p13.
[74] www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

FIGURE 2.3

Components of domestic electricity bills in Northern Ireland, 2013

Retail tariff	=	**Wholesale costs**	+	**SSS charges & cairt**	+	**PSO levy**	+	**Use of systems**	+	**Supplier charge**	+	**NIRO costs**	+	**Correction factors**
What customers pay		Generation costs (cost of procuring electricity), capacity costs, imperfections (costs of electricity constraints), and MO charges		For system planning, operation and dispatch		PSO costs which must be spread across all customers		Costs of transmission and distribution of electricity		Costs to supply electricity to customers eg meter reading, billing		Net costs of NI Renewable Obligation – NIRO costs relate to government obligation to sell a proportion of their output as renewables		The difference between allowed revenue and actual recovered revenue (mechanism whereby differences between forecasts for tariff-setting and actuals can be recouped or returned to customers) and first year effect
Split 13/14 **100%**		**58%**		**4%**		**2%**		**22%**		**9%**		**2%**		**3%**
Split 12/13 **100%**		**62%**		**3%**		**2%**		**25%**		**9%**		**1%**		**–2%**

Source: www.uregni.gov.uk/uploads/publications/Retail_Tariff_Background_Briefing_May_2013.pdf.

2.77 CCNI said that it would accept that for the current Power NI tariff 25 per cent was the figure to use. However, it noted that this was just for Power NI's standard credit tariff. CCNI said that other tariffs of Power NI (eg direct debit payment and keypad) were cheaper and the tariffs of other suppliers considerably lower. Therefore, CCNI said that 25 per cent was the lowest figures that NIE network charges represented in Northern Ireland electricity bills.

2.78 Over the last five years NIE's charges have been reflected in domestic and industrial and commercial customers bills as shown in Table 2.5.

TABLE 2.5 **NIE network charges, annual cost for average use**

	Annual cost for average use (TUoS + DUoS) – nominal price base (£)				
Customer type	*07/08 Nov 08–Sep 08 11 months costs*	*08/09 Oct 08–Sep 09*	*09/10 Oct 09–Sep 10*	*10/11 Oct 10–Sep 11*	*11/12 Oct 11–Sep 12*
Domestic	121	138	143	127	148
Small business (quarterly billing	454	517	538	478	554
Half-hourly metered MV <70 kVa	1,010	1,150	1,197	1,064	1,233
Half-hourly metered MV	6,983	7,951	8,279	7,357	8,523
Half-hourly metered HV	35,618	40,657	42,059	37,300	53,640
Half-hourly metered EHV	112,928	129,485	132,420	116,996	139,314

Source: NIE.

CCNI

2.79 The Consumer Council is an independent consumer organization. CCNI has a statutory remit to promote and safeguard the interests of consumers in Northern Ireland and it has specific functions in relation to energy. Under the Energy (NI) Order 2003 the Consumer Council is empowered to:

- make proposals and provide advice and information and represent consumers on energy matters;
- obtain and keep under review information about consumer issues and the views of consumers on those matters;

- investigate and seek to resolve consumer complaints against companies about regulated matters;
- give information to Ministers, the UR, licence holders and any other body with a consumer interest; and
- publish information about complaints.

Customer concerns

2.80 CCNI undertook consumer research in June 2012 into what consumers wanted from the electricity network—see Table 2.6.

TABLE 2.6 **CCNI research into customer priorities**

per cent

	First priority	*Second priority*
The lowest possible price	69	20
A highly reliable supply with the lowest possible number of power cuts	19	52
That as much electricity as possible is generated by renewable means, ie from sustainable sources such as wind power	7	18
Don't know	5	10

Source: Consumer Council research, June 2012 (base 1,020 consumers).

2.81 While the lowest possible price for electricity was, perhaps unsurprisingly, the top priority for consumers, and it was the first or second priority for 89 per cent of respondents, 71 per cent of respondents said that reliability of supply was the top or second priority. There is thus recognition by consumers of its importance.

2.82 CCNI told us that its relationship with NIE over complaints handling was excellent. NIE was very cooperative and thorough in complaint investigations. CCNI also said that NIE was willing to help in other instances, for example on switching issues between suppliers where CCNI could not distinguish where fault lay.

2.83 Consumer complaints received by CCNI concerning electricity generally were relatively low. In 2012/13, CCNI received 194 inquiries regarding NIE. In addition, seven approaches were resolved at the stage 1 investigation stage, seven reached stage 1 referral and two others were treated as full complaints.

Fuel poverty

2.84 The UR and others drew our attention to the issue of fuel poverty in Northern Ireland, relating this in part to the economic crises that have affected the UK and have hit particularly hard in Northern Ireland.[75] Fuel poverty (which is defined as where more than 10 per cent of disposable household income needs to be spent on maintaining adequate heating provision) is much higher in Northern Ireland compared with other parts of the UK. The proportion of households in fuel poverty in 2011 in all parts of the UK is set out in Table 2.7.

TABLE 2.7 **Households in fuel poverty, 2011**

	%
England	15
Wales	25
Scotland	29
Northern Ireland	42

Source: www.gov.uk/government/uploads/system/uploads/attachment_data/file/199833/Fuel_Poverty_Report_2013_FINALv2.pdf.

2.85 The 42 per cent of households in fuel poverty in Northern Ireland represents some 294,000 households. 14.6 per cent of homes (103,000) need to spend 15 per cent of income to meet the required fuel expenditure and 5.9 per cent need to spend 20 per cent of household income.

2.86 The main reasons for the high level of fuel poverty in Northern Ireland are a combination of lower incomes, higher fuel prices, and high dependence on oil for heating. Natural gas networks have only recently been developed in Northern Ireland and serve only certain areas. In Northern Ireland 68 per cent of homes (rising to 82 per cent in rural areas) use home heating oil to heat their homes. In 2010, just over a

[75] UR Statement of Case, UR2, paragraph 23.

million households in GB were estimated to have oil-fired central heating; just over 4 per cent of all households.[76] CCNI research suggests that in Northern Ireland on average it costs £657 each year more to heat a home using home heating oil compared with gas. However, the difference can vary significantly depending on whether condensing or non-condensing boilers are used, the quantity of oil purchased and other energy-saving measures that are in place. Energy prices do vary, particularly home heating oil which is subject to almost daily fluctuations in price. However, as an extreme example, where a household uses 20-litre emergency refills of home heating oil (rather than larger tanker deliveries) the cost of heating is estimated by CCNI to be 127 per cent more expensive than using gas.

2.87 CCNI figures (see Table 2.8) show that overall energy bills (for all sources of energy: oil, gas and electricity) in Northern Ireland are significantly higher than in GB and have risen at a much faster rate between 2001 and 2011.

TABLE 2.8 **Average household energy bills, 2001 and 2011**

£

	Average bill 2001	*Average bill 2011*	*Percentage increase 2001–2011*
Northern Ireland	768.55	2,368.71	208
GB	541.33	1,258.09	132
Difference	227.22	1,110.62	389

Source: CCNI (from DECC, CCNI, Sutherland tables, Consumer Focus, Power NI, Phoenix Supply Limited, firmus energy).

2.88 46 per cent of households in Northern Ireland which use electricity for heating are in fuel poverty compared with 59 per cent using solid fuel, 44 per cent using home heating oil and 34 per cent mains gas. However, only 3 per cent of households in

[76] *Energy consumption in the UK 2012*, DECC, Table 3.14.

Northern Ireland use electricity for central heating (compared with 68 per cent of households using home heating oil).[77]

2.89 While electricity is used to power a range of household appliances, and for lighting, cooking, etc, given the low volumes of households using electricity for heating in Northern Ireland (3 per cent) it seems that electricity prices are not a major factor in the high fuel poverty levels in Northern Ireland. However, for the small number of households which do use electricity for heating and who are on low incomes, obviously the price of electricity is very important.

Business customers

2.90 As shown in Figure 2.4, while domestic consumers in Northern Ireland are paying prices for their electricity which are slightly below the median for the EU, business customers[78] are paying prices which are among the highest in the EU. Only in Italy are business customers paying a higher price per kWh of electricity than in Northern Ireland.

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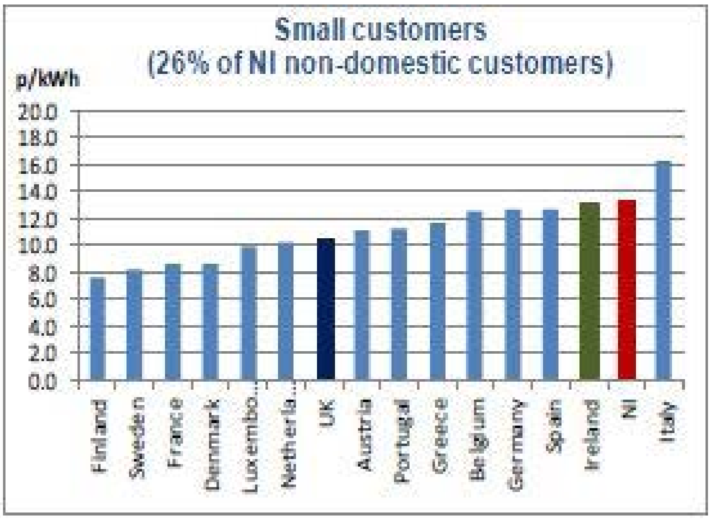
[77] www.nihe.gov.uk/northern_ireland_house_condition_survey_main_report_2011.pdf.
[78] The prices shown relate to small industrial and commercial customers with an annual consumption of less than 500 MWh.

FIGURE 2.4

Electricity charges for small business customers by country, July to December 2011



Source: NIAUR March 2013: NI Electricity Prices Data and Comparisons Information paper.

2.91 For domestic consumers, Northern Ireland prices were around the EU average; for very small industrial and commercial (I&C) consumers, electricity prices were also around the EU average. Small I&C consumers account for around 70 per cent of all non-domestic consumers in Northern Ireland; and for the remaining 30 per cent of I&C consumers electricity prices were among the highest in Europe.

2.92 As shown in Table 2.1, about 14 per cent of NIE's income comes from distribution charges from small industrial or commercial customers using low voltage and charges for street lighting. 30 per cent of its distribution income comes from larger industrial and commercial customers using low voltage and high- and very-high-voltage users.

Renewable energy

2.93 CCNI consumer research (see Table 2.6) showed that 7 per cent of consumers considered increased use of renewable fuels as their first priority and 18 per cent placed it as their second priority in relation to energy.

2.94 However, other CCNI research also indicated that an increasing number of consumers were willing to pay more for their fuel so that renewable energy could be utilized. In answer to the question ‘Are you willing to pay an additional cost on your energy bill so Northern Ireland can increase the amount of renewable energy it uses?’, in the 2010 survey 54 per cent said yes, and 46 per cent no (in 2009, the figures were 41 and 59 per cent respectively).

3. The existing price control conditions and the public interest

3.1 The first question in the reference to us is whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest (paragraph 1.1). Our terms of reference also require us to consider whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences.

3.2 Therefore we consider in this section whether the existing (ie RP4) price control conditions are against the public interest, and whether the continuation of each Licence operates against the public interest absent further conditions relating to recording, reporting and monitoring of information. As necessary, we refer to other parts of the report.

3.3 In their respective submissions to us, the UR and NIE both said that there was agreement that the existing RP4 price control conditions were now against the public interest,[79,80,81] principally on the basis that they were only intended to operate until 31 March 2012. The UR said:

> … it is common ground as between us and NIE that NIE's current price control licence conditions operate against the public interest. It was only ever envisaged that they would operate until 31 March 2012, and there are several practical difficulties with their continued operation beyond that date. More fundamentally, we consider, and NIE also contends, that the public interest requires a new price control to reflect the needs of the network and consumers over the next five years, rather than the

[79] UR Statement of Case, UR2, paragraph 16.
[80] NIE Statement of Case, Chapter 1, paragraph 1.7.
[81] ibid, Chapter 2, Part B, paragraphs 7 & 8, p22.

needs of the period 2007-2012 that are reflected in the design of the current price control.

3.4 NIE said:

> NIE agrees with the Utility Regulator that the [transmission and distribution] price control conditions of NIE's Licences need to be modified to contribute to the attainment of the statutory objectives laid down in Article 12 of the Energy (Northern Ireland) Order 2003 (Energy Order). However, NIE disagrees with the Utility Regulator as to what form those modifications should take.

and:

> NIE and the Utility Regulator both consider that the continuation without modification of NIE's existing price control conditions operates, or may be expected to operate, against the public interest. In these circumstances, the focus of the Competition Commission's investigation should be on whether the adverse public interest effects arising from the current price control can be remedied or prevented by modifications to NIE's licence conditions.

3.5 In NIE's view, the adverse public interest effects arising from the current price control were that NIE would have inadequate revenue to enable it to provide transmission and distribution services during RP5 and beyond to the standard required by its statutory and licence obligations, and to satisfy the reasonable demands of customers in terms of safety, security and quality of service.

3.6 NIE and the UR's reasons are summarized in paragraphs 3.42 to 3.51.

3.7 In this section, we:

- describe RP4 in more detail;
- summarize the parties’ submissions on RP4 and the public interest (paragraphs 3.42 to 3.51); and
- consider whether and in what ways RP4 operates, or may be expected to operate, against the public interest, and what detriments to the public interest arise as a result (paragraphs 3.52 to 3.77).

The RP4 Price Control Conditions

Introduction

3.8 This subsection contains:

- an overview of the key features of the RP4 price control (paragraph 3.9);
- a summary of the different sections (or paragraphs) in the current price control licence conditions (paragraphs 3.10 and 3.11);
- a more detailed description of section 2 of the Price Control Conditions, which provides formulae for the calculation of the maximum regulated revenue for NIE (paragraphs 3.12 to 3.28);
- a discussion of the RP4 capital expenditure ‘budget’ which featured in the UR’s final proposals for RP4 but is not reflected in the price control licence conditions (paragraphs 3.29 to 3.38); and
- the reasons the UR originally offered for its choice of regulatory design for RP4 (paragraphs 3.39 to 3.41).

Overview of the key features of the RP4 price control

3.9 In summary, NIE told us that the key features of the RP4 price control were:

- The allowance for controllable opex in each year of RP4 was set equal to the RPI-indexed level of actual costs incurred during the corresponding year in RP3 subject to one-off reductions for the first two years of RP4 (of £2.6 million and £1.6 million respectively). The UR considered that this approach would simplify the calculation of the opex allowance but would also incentivize NIE to reduce costs creating customer savings.

- Uncontrollable opex (ie rates, wayleave costs and licence fees) did not form part of the rolling mechanism and was recoverable on a pass-through basis.
- The allowance for pensions costs in each year of RP4 was set equal to the RPI-indexed level of actual costs incurred during the corresponding year in RP3 subject to a disallowance of £225,000 a year in respect of ERDCs.
- RAB additions during RP4 were based on actual capex rather than allowed capex, with a separate mechanism for incentivizing capital efficiency. The five-year capex budget (net of customer contributions) was agreed at the start of RP4 (£374 million in 2010/11 prices, compared with £306 million in RP3 in 2010/11 prices). The RP4 price control allowed NIE to charge depreciation on such capex from then on (in accordance with the UR's specified depreciation profile), and to earn an allowed rate of return on such capex from the year in which it was incurred. Non-core capex (eg expenditure on renewables projects) was provided for separately through the D_t term of the price control subject to the UR's approval on a project by project basis.
- The capex efficiency incentive mechanism required annual reporting by NIE on the progress of its capex programme and significant changes in its investment priorities. Notified efficiency gains related to procurement of materials and services and labour productivity. For every £1 of demonstrated efficiency, NIE retained 38.9p and customers retained 61.1p.
- Cost of capital provided for the allowed rate of return to be set at the GB DNO level for the distribution portion of the regulated asset base. The UR provided for a 0.35 per cent post-tax reduction from the GB rate in relation to the assumed 18 per cent of transmission assets. This resulted in a post-tax real rate of return of 4.84 per cent for 'distribution assets' and of 4.49 per cent for 'transmission assets'.

The distribution rate of return tracked any downward movement in the GB rate at the next price control (affecting the last two years of NIE's scheduled RP4 period).

Structure of current price control conditions

3.10 The RP4 Price Control Conditions are set out in Annex 2, the 'Transmission and Distribution Charge Restriction Condition' of NIE's transmission and distribution Licences. The two Licence documents have identical Price Control Conditions.

3.11 The Price Control Conditions take 29 pages and are structured as follows:

- Section 1 provides definitions.
- Section 2 contains formulae and data tables to calculate the restriction on the maximum regulated transmission and distribution revenue. The calculations in section 2 rely, in part, on methods that are specified in a direction issued by the UR in December 2006 (referred to as the 2006 Direction). This section is discussed in more detail below (paragraphs 3.12 to 3.28).
- Section 3 defines some rules and adjustments that are triggered when regulated transmission and distribution revenue exceeds the maximum regulated transmission and distribution revenue.
- Section 4 obliges NIE to provide some data to the UR to demonstrate compliance with sections 2 and 3.
- Section 5 defines 'excluded services'. Income from these services is excluded from the restriction on the maximum regulated transmission and distribution revenue. Excluded services include the provision of new connections.
- Section 6 allows the price control to be suspended by the UR in connection with a Security Period under the Northern Ireland Fuel Security Code.
- Section 7, 'Duration of transmission and distribution charge restriction conditions', defines a procedure for terminating the price control.

- Section 8 provides for the maximum regulated transmission and distribution revenue to be adjusted in some cases of change of law.
- Section 9 requires NIE to ‘make available’ funding to run a Vulnerable Customer Programme. This ceased to have any effect in 2010.
- Section 10 requires NIE to ‘make available’ funding to run a Sustainable Networks Programme. This ceased to have any effect in 2012.
- Section 11 requires NIE to report information about capital expenditure and capital expenditure plans.
- Section 12 requires NIE to report information about its calculation of tax and tax capital allowances.

More detailed description of section 2 of the Price Control Conditions

3.12 This subsection summarizes aspects of the revenue restriction in section 2 of the price control Licence conditions. It provides more detail on the implementation of the features of the price control summarized in paragraph 3.9.

3.13 Clause 2.1 is an obligation on NIE to use its best endeavours to ensure that in each year its regulated transmission and distribution revenue does not exceed the maximum regulated transmission and distribution revenue. The maximum regulated transmission and distribution revenue is defined as the sum of two components: *(a)* the maximum core revenue in relevant year t (MD_t), for which the remainder of section 2 sets out the formulae; and *(b)* a term which now has no effect and takes the value of zero.

3.14 Clause 2.2 specifies formulae to calculate the maximum core revenue in reach of the financial years ended 31 March 2003 to 31 March 2007.

3.15 Clause 2.3 specifies formulae to calculate the maximum core revenue in the financial year ended 31 March 2008 and subsequent years. We highlight some particularly relevant aspects.

3.16 For ease of explanation, we can write the formula for the maximum core revenue as follows:

$$M_{Dt} = \text{Min}(PC_t, CPA_t) + Z_t$$

3.17 Leaving aside the Z_t element for now, the restriction on maximum core revenue in year t is specified as the minimum of two elements:

- A price-capped regulated revenue entitlement term (PC_t) which is obtained by taking a specified value (0.0181), adjusting it for RPI inflation, then multiplying it by a forecast of the number of units of electricity transmitted and distributed for year t which is specified in the Licence, but only for the financial years ended March 2008 to March 2012. This term also includes an adjustment for any differences between the actual levels of certain 'uncontrollable' operating costs in year t and forecasts of those costs specified in the Licence.
- A term (CPA_t) which is described as the 'composite proposal allowance' for year t. We describe this term in more detail below.

3.18 The PC_t reflects one aspect of the UR's RP4 proposals, which was to cap NIE's revenue by reference to a transmission and distribution 'price' of 1.81p/kWh. In its draft proposals paper, the UR proposed to 'cap [transmission and distribution] prices during RP4 at the current level'.[82] The PC_t term in the Licence does not actually operate as a cap on prices. Instead, it is calculated as a notional or average price multiplied by a volume forecast that is hardcoded into the Licence. It operates as a revenue limit that is subject to RPI inflation. Further, part of the CPA_t term—

[82] UR Draft Proposals Paper, December 2005, p18.

discussed further below—represents an adjustment in respect of revenue forgone as a result of the PC_t term biting in the previous financial year. The UR told us that the PC_t did bite in the financial year ended 2008. In other years it had not had a bearing on the calculation of maximum revenues for NIE.

3.19 Subject to the limit from the PC_t term not biting, the maximum regulated revenue is calculated by reference to the CPA_t term. CPA_t incorporates all of the principal building blocks that make up the price control (ie opex, capex, weighted average cost of capital (WACC), depreciation and pensions). The formula for determining CPA_t is as follows:

$$CPA_t = CO_t + P_t + UO_t + Ret_t - TA_t + Dep_t + Tax_t + RRF_t$$

where these terms refer to, for each year t:

CO_t – an allowance for 'controllable' operating costs

P_t – an allowance for pension costs

UO_t – an allowance for certain 'uncontrollable' operating costs

Ret_t – return on capital

TA_t – an adjustment in respect of the allowed return on transmission assets

Dep_t – an allowance for depreciation

Tax_t – an allowance for tax

RRF_t – is an adjustment term which has the effect of compensating NIE for any under-recovery of revenue that it would have been due under the CPA_t term in the previous financial year but which it could not recover in that year because of the revenue cap imposed by the PC_t term in that previous financial year (this compensation would still seem to be constrained by the cap imposed by the PC_t term in the current financial year).

3.20 In relation to elements of the CPA_t term, we note that the allowance for depreciation (Dep_t) and return on capital (Ret_t) are calculated according to the value of NIE's regulatory asset base (RAB) which is updated each year to reflect NIE's actual capital expenditure that year.

3.21 Regardless of whether the PC_t or the CPA_t term applies, the maximum regulated revenue also features a number of terms which fall under what we have labelled Z_t above, and which comprise:

- An allowance for change of law costs calculated in accordance with the change of law provisions in section 8, in relation to the years 2008 to 2012.
- An adjustment (PPS_t) to give effect to a profit-sharing term in respect of NIE Powerteam Limited.[83]
- An allowance (D_t) which is defined as the sum of eight different elements. These elements include any amount arising under the arrangements specified in the UR's 2006 Direction to provide NIE with financial incentives in relation to the efficiency of its capital investment. In the 2006 Direction these amounts are calculated by reference to defined measures of labour productivity and procurement efficiency and a rule that, for every £1 of demonstrated efficiency, NIE should retain 38.9p. The elements falling under the D_t term also include other costs that the UR determines should be included within the D_t allowance, following an application from NIE.
- A revenue entitlement (NSI_t) associated with interconnectors with the Republic of Ireland. For the financial years ended March 2008 to March 2012 this is defined as a specified value in the Licence, adjusted for RPI inflation.
- A corrector factor (KD_t), which can take a positive or negative value. It is calculated as the difference between the regulated revenue that NIE was entitled to collect in year t–1 and the regulated revenue that NIE actually collected, adjusted by application of a defined interest rate. The effect is that charges in year t are

[83] During RP4 there was an arrangement pursuant to which 50 per cent of NIE Powerteam's profits were credited to customers in the form of lower allowed revenue.

adjusted for any over- or under-recovery of revenues against the maximum permitted amount in year t–1.

3.22 Each of these terms of the CPA_t formula is required to be determined on the basis specified for that term in paragraph 2.3 of Annex 2. In some cases, Annex 2 cross-refers to a methodology contained in a direction made by the UR in the 2006 Direction. We now describe the rules applicable to determining some of the terms of the CPA_t formula for each year.

3.23 The allowance for controllable opex, CO_t, is determined by reference to the term ACO_{t-5}, being the level of actual controllable operating costs in relevant year t–5 (ie five years previously) and then adjusting it for inflation in the intervening period. This reflects the 'rolling opex' arrangement that formed the basis of the RP4 final determination. For the years ended 2008 to 2010, values for ACO_{t-5} were specified in Annex 2 of the Licence. The Licence says that for the financial years to March 2011 and March 2012, it should be calculated in accordance with the UR's 2006 Direction. The allowance for pension costs P_t in year t is calculated by taking a measure of NIE's cash contributions to the relevant pension scheme five years ago and adjusting for RPI inflation.

3.24 The allowance for uncontrollable opex, UO_t, is set at the level of uncontrollable costs in relevant year t calculated as the aggregate of:

- amounts paid by NIE in respect of rates levied on NIE's transmission and distribution assets;
- amounts incurred by NIE in respect of wayleaves; and
- amounts allocated in respect of Licence fees payable to the UR.

3.25 The rate of return NIE is allowed to earn on its RAB is expressed as a vanilla WACC (VWA_CC_t). The allowed return, R_et_t, is calculated by multiplying the average value of the RAB in year t by the VWACC in year t.

3.26 The RAB term is calculated in accordance with the methodology set out in the 2006 Direction. That methodology proceeds on the basis that all 'operational capital expenditure' (ie actual capex) in a particular year will be added to the RAB for that year.

3.27 In 2008, 2009 and 2010, $VWACC_t$ was set equal to 0.05545 (ie 5.545 per cent). In 2011 and 2012, $VWACC_t$ was set equal to the lower of: *(a)* 0.05545; and *(b)* $VWACC_{2010}$, where $VWACC_{2010}$ means the weighted average cost of capital (stated as a decimal number) calculated on the basis of the values for the pre-tax return on debt and the post-tax return on equity used in determining the regulated revenue entitlement for the DNOs in GB for the distribution price control commencing on 1 April 2010. NIE noted that Annex 2 made no provision as to how to calculate $VWACC_t$ for any period after 31 March 2012.

3.28 The points above are not a complete or precise description of the calculation of NIE's maximum regulated revenue under the current Licence conditions, but are intended to capture the key elements relevant to understanding the operation of the current conditions.

The RP4 capital expenditure 'budget'

3.29 NIE and the UR told us that for the RP4 price control period there was a 'budget' relating to NIE's capital expenditure.

3.30 The Price Control Conditions of NIE's Licence (Annex 2) make no reference to any budget relating to NIE's capital expenditure. As explained above, the calculation of the maximum regulated revenue is updated each year in light of NIE's actual capital expenditure. There are no constraints in the Licence conditions or the 2006 Direction that have the effect of limiting the amount of NIE's capital expenditure that it can add to its RAB and feed through to the calculation of the maximum regulated revenue.

3.31 The UR's final determinations (paragraph 3.11) recognize that there is no capital expenditure budget within the Licence conditions and explain that the amount of capital expenditure 'to be spent in RP4' is stated in the RP4 final determination. When setting the price control for the RP4 period, the UR used the terminology of 'final proposals' rather than 'final determinations'. The UR's final proposals document for RP4, dated September 2006, is just seven pages long. This document refers to a capital expenditure 'budget' which seems to have been established by the UR in light of a review by its consultants, Mott MacDonald, of NIE's assessment of the overall network investment requirement for RP4. The UR proposed that the 'capex budget' for RP4 should be based on the assessment of investment requirements that is set out in a table on page 4 of its final determinations document, which implies a total figure of £312 million over the five-year period from April 2007 to March 2012.

3.32 Whilst this budget was not specified in the Licence conditions or the 2006 Direction, NIE seems to have treated it as an important part of the price control for RP4. NIE's owner at the time, Viridian Group Plc, issued a press release dated 6 September 2006 to say that its subsidiary NIE had accepted the final proposals published that day by the UR in connection with the five-year price control to apply to NIE's transmission and distribution business with effect from 1 April 2007 (RP4).[84] The press release says the following about the capital expenditure budget:

> As part of its acceptance, NIE has agreed to work to a capital expenditure budget for RP4 of £312m [footnote: Net of customer contributions, in 2004/05 prices and excluding investment associated with interconnection and the connection of renewable generation], in line with [the UR's] consultation paper of 9 June 2006.

3.33 NIE and its sister companies subsequently described the capital expenditure budget as a key feature of the RP4 price control. NIE Finance Plc issued an 'Offering Circular' on 31 May 2011 relating to the issuance of £400 million of 6.375 per cent Guaranteed Notes due in 2026, which were unconditionally and irrevocably guaranteed by Northern Ireland Electricity Limited,[85] which included information on 'key aspects of the RP4 price control' and says the following about capital expenditure (page 44):

> The five year capital expenditure budget (net of customer contributions) agreed at the start of RP4 was £374m (in 2010/11 prices) compared to £306m in RP3 (in 2010/11 prices). This investment is driven by the need to replace worn assets and to meet continued growth in customer demand. Capital expenditure is added to the RAB as it is incurred and earns the regulatory rate of return.

3.34 NIE has also referred to a five-year capital expenditure budget (net of customer contributions) in its annual report and accounts. NIE seems have updated the reported budget in line with inflation. For instance, it refers to a budget of £345 million (in

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[84] www.viridiangroup.co.uk/default.aspx?CATID=216&CID=1346, retrieved 17 June 2013.
[85] www.nie.co.uk/documents/OfferingCircularGuaranteedNotes.aspx, retrieved 16 June 2013.

2007/08 prices) in its report for the year ended March 2008 and a budget of £374 million (in 2010/11 prices) in its report for the year ended March 2011.

3.35 In the CC's experience, the absence of any reference in the Licence conditions to the budget referred to by the UR and NIE is not extraordinary. It has not been uncommon for some of the regulatory rules and financial arrangements proposed by a UK regulator to be omitted from the Licence modifications intended to implement those proposals. Regulators such as Ofgem and Ofwat have implemented rules or policies on financial adjustments relating to one price control period as part of their proposal for price controls for the next price control period. For instance, calculations of the level of a price control for a company for the period 2010 to 2015 might include a financial adjustment intended to implement a rule relating to the difference between the company's out-turn expenditure in 2007 and the forecast for its 2007 expenditure that was used to calculate the price control for 2005 to 2010.

3.36 However, where important aspects of a regulator's price control proposals are omitted from the Licence, we would expect some explanation of the financial adjustments that the regulator intends to make at some future date. We have not found an explanation of the nature of the capital expenditure budget and, in particular, what was intended to happen if NIE spent more than the budget:

- The UR's final proposals document for RP4 provides no explanation of what constraints, if any, its decision on the capital expenditure budget was intended to impose on NIE. This document does not explain what adjustments, if any, might be made to NIE's future revenue restrictions or RAB in the event that NIE's capital expenditure exceeded the stated budget.
- We have not found any explanation of the budget in the UR's first proposals paper for RP4 (December 2005), the UR's further consultation paper on RP4 (June 2006), nor the UR's final proposals for RP4 (September 2006).

- We reviewed a document produced by NIE entitled 'T&D price control for RP4: the composite proposal' and dated March 2005. This document is marked confidential and was submitted to us by the UR and referred to by the UR as the 'RP4 Composite proposal'. The UR drew on NIE's composite proposal in developing its approach to RP4. This document is 25 pages long, including appendices. It did not shed any more light on the capital expenditure budget.

3.37 What does seem clear is that any capital expenditure budget that NIE agreed to as part of its acceptance of the UR's RP4 price control proposals related to the period from April 2007 to March 2012.

3.38 In its proposals for a new RP5 price control, the UR has not proposed any similar 'budget' arrangements.

The UR's intentions in the design of RP4

3.39 In 2005 when the UR was considering the possible design of price controls for RP4, it said that the design of the RP4 proposals reflected the following principles:

- a rule-based approach to the opex allowance that strengthened efficiency incentives and shared the savings with customers;
- a capex allowance based on actual rather than forecast expenditure, together with strengthened capex efficiency incentives; and
- an allowed rate of return on assets consistent with established precedent.[86]

3.40 In relation to opex, the UR noted that determining the efficient level of opex to allow (typically involving an examination of the company's operating cost base, benchmarking it against the cost bases of other electricity network companies both

[86] Northern Ireland Authority For Energy Regulation, Northern Ireland Electricity – Transmission And Distribution Price Control 2007–2012 Proposals Paper, 14 December 2005.

nationally and internationally, and undertaking a very detailed item by item analysis of individual expenditure category) was time consuming and resource intensive, and would be complicated by differences in the way that companies reported their costs. It also noted that under the ‘traditional’ approach the incentive to reduce costs diminished as the regulatory period progressed as the period before they were reflected in lower allowances in the next price determination was reduced. The UR therefore proposed a rolling mechanism where actual controllable opex in each year of the existing price control period was rolled forward with RPI indexation to become the controllable opex allowance for the corresponding year in the next period. Uncontrollable opex would be passed through. The UR told us that one explanation of this approach was that it implicitly assumed that NIE’s opex needs were broadly stable from one period to the next, subject to further adjustment for specific items where NIE’s business changed from one period to the next. On that basis, this system provided a five-year return on efficiency improvements or other outperformance.

3.41 The UR also noted in relation to capex, under the traditional approach, regulated revenue (to cover the costs of financing return and depreciation) of new capital expenditure depended on forecast capex. Once the capex allowance was agreed there was an incentive on the company to underspend and increase profits by avoiding the financing costs associated with the underspent capex. It noted that the UR faced difficulties in distinguishing an underspend due to valid efficiency gains and one due to investment being deferred into a later period. It therefore proposed for RP4 that the regulated entitlement would be dependent on pass-through of actual capex rather than allowed capex. It proposed separate mechanisms to incentivize capital efficiency. It said that this, combined with annual reporting of investments, would benefit customers through the savings in RAB financing costs, with improved transparency around the investment programme.

Parties' submissions on RP4 and the public interest

UR's submissions on RP4

3.42 The UR said that continuation of the adapted RP4 approach under its 'pragmatic approach' was an interim solution without adequate legal certainty and it was self-evidently not in the public interest for it to continue. In addition, the UR argued that some of the elements of the interim solution could not be said to be in the long-term public interest from a substantive perspective. It said that continuation would not promote efficiency and economy on the part of NIE and consequently would not adequately protect the interests of consumers in respect of services provided and prices charged.

3.43 The UR told us that the RP4 price control was not a good one. It said that history had shown that the decision to accept NIE's proposed combination of a rolling opex allowance with uncapped pass-through remuneration for capex provided NIE with an incentive to engage in regulatory gaming. It said that the structure of RP4 essentially had the effect of giving NIE a blank cheque to spend on capital works without clear definition of deliverables or sufficient incentive to be efficient. This was because capex was fully remunerated through the RAB irrespective of whether it was efficiently incurred, and it said that NIE was not incentivized to engage with customers to develop a plan for capex based on their needs and their willingness to pay.

3.44 Similarly in relation to operating expenditure, the UR said that the RP4 allowance reflected opex expenditure from five years earlier, whether or not that opex had been efficiently incurred and irrespective of any pressing need for new categories of opex. It also said that the five-year rolling mechanism for controllable opex would provide insufficient revenue for NIE to cover its efficient/unavoidable costs during RP5. It said that it was not in the public interest for this mismatch between revenue and costs to be left in place.

3.45 The UR noted that it was continuing to apply the WACC determined for the RP4 period, ie 4.7 per cent. It considered that figure to be substantially higher than NIE's current cost of capital (given the movements and developments in the financial markets) and therefore higher than the rate of return on capital that would be in the public interest.

3.46 It also believed that the Licence in its current form did not address its concerns around the issues of transparency and accountability, which the UR had proposed to address by way of including a new condition (a draft of which was included with the Final Determination) relating to the appointment of a reporter. It said that continuation of RP4 would not enable:

(a) appropriate mechanisms to be put in place to ensure that NIE was held accountable for the money that it received and that customers derived real benefit from the substantial sums that they were required to pay towards the electricity network in Northern Ireland; and

(b) appropriate mechanisms to be put in place to ensure that there was, going forward, much more transparency and accountability in NIE's activities, in its recording, reporting and monitoring of information in relation to price controls and in it accounting practices.

3.47 Last, it considered that continuation of RP4 would not enable appropriate treatment of pension costs, including financing the repair of NIE's deficit in a way that was fair for both customers and NIE.

NIE's submissions on RP4

3.48 NIE submitted that the existing price control conditions as a whole operated against the public interest because they could no longer function effectively at all. It said that the existing conditions did not include certain regulatory mechanisms (eg in relation to performance and other incentive arrangements) which NIE considered were in the best interests of consumers. It argued that following the expiry of an existing price control, the interests of consumers required that a fresh assessment was made of the regulatory mechanisms and other tools that formed the basis of the price control going forward. It argued that the CC should, when considering whether the existing charge restriction condition operated against the public interest, make an assessment of whether the regulatory mechanisms and other tools embodied in that condition are best calculated to deliver optimum outcomes for consumers. NIE said that this was because the existing price control conditions would operate against the public interest to the extent that they fail to attain the UR's statutory duties, which are themselves directed at attaining optimal outcomes for consumers.

3.49 It said that:

(a) RP4 failed effectively to cap NIE's transmission and distribution charges;

(b) RP4 failed to provide NIE with effective incentives to provide an appropriate quality of services, in terms of the achievement of certain output standards (eg in relation to network performance);

(c) to the extent that RP4 caused the UR to believe that it might procure the continuation of the charge control by specifying new values for certain elements of the price control equation, created uncertainty which exposed NIE to risks and costs, and constrained its freedom to manage and run its T&D network as it judged best;

(d) RP4 failed to provide an effective mechanism for timely, fair and efficient resolution of claims by NIE for an adjustment to its allowed revenues; and

(e) some of RP4's provisions were unclear and created further uncertainty.

3.50 For example, NIE said that several of the terms comprising the CPA_t term were defined in the existing charge restriction condition in a manner that did not provide numerical values, or a means of calculating those values, for those terms for any period after 31 March 2012: the allowance for controllable opex; the allowance for pension costs; the allowed return; the adjustment in respect of the allowed return on transmission assets; and the allowance for tax costs. It also said that the RP4 arrangements made no provision for NIE's revenue requirements for RP5, such as new opex requirements (eg for Enduring Solution IT system[87] or provision for injurious affection), no restriction applied to RP5 capex spend referencing NIE's requirements, and the allowed rate of return took no account of the actual cost of capital. It also detailed some aspects of the regulatory mechanisms in RP4 which it said could not now be regarded as best calculated to deliver optimum outcomes for RP5.

3.51 It said that in consequence there was a risk that consumers would not be protected against excessive prices, and that NIE might not provide services of an appropriate standard. It said that uncertainty would be created which would deter capex and increase the cost of capital for NIE. It also argued that NIE faced uncertainty over requests for adjustments to allowed revenues and over interpretation of part of the tax term in the charge control formula.

[87] The UR told us that it did approve a large expenditure budget for the Enduring Solution IT system during the period RP4 was extended.

Our assessment

The price control conditions and the public interest

3.52 We now consider whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest, and if so, what the effects adverse to the public interest would be.

3.53 NIE said that an assessment of whether the current Licence conditions operated against the public interest could be made by deciding what the best possible price control would be for NIE and then comparing the current Licence conditions against that desirable price control.

3.54 However, we do not consider it practicable to identify an optimal price control regime given the inherent uncertainties in regulation, that regulatory experience and notions of best practice continue to evolve, given the limited time and resources available to us, and because, in order to maintain stability and clarity of the regulatory environment, we do not wish to intervene in aspects of the price control where we do not have evidence that current arrangements are against the public interest.

3.55 The approach we have adopted is to consider for each aspect of the price control conditions whether it operates against the public interest and, if so, which is the best alternative available that will address the adverse effect, and best serve the public interest. This includes the determination of appropriate allowances and any consequent adjustments arising from redesign of the price control. We then consider whether the overall effect of our proposals operates in the public interest or whether any aspects or the overall package should be modified. We consider the public interest with regard to the approach outlined in paragraphs 1.13 to 1.15. In particular, in making our determination, we have had regard to the duties of the UR as set out in paragraphs 2.40 to 2.52.

3.56 As detailed below, we outline areas of the current price control conditions we consider to operate against the public interest. Our explanations as to why we consider alternative conditions and allowances we have identified provide outcomes which are more beneficial to the public interest are set out in the relevant sections of the rest of this report.

3.57 Our evaluation assumes that tariffs to customers are set in line with changes in allowable revenue. We note that NIE has some ability to choose how tariff changes are implemented and to vary changes between transmission and distribution and between different classes of customer. In the absence of any specific methodology for implementing tariff adjustments, and absent indications of intended tariff changes for different groups, we have assumed that any changes do not affect any particular class of customers disproportionately.[88] We also note that the UR approves NIE's tariffs, which provides some protection against any particular group being disadvantaged.[89]

Whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest

3.58 We have provisionally determined that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest because:

- application of the current price control conditions generates uncertainty;
- aspects of the price control design are not sufficient to protect the interests of consumers;
- the current price control conditions provide for excessive cost of capital; and
- the duration of the RAB for short-lived assets (specifically tree cutting) operates against the interest of future customers.

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[88] Such concerns would be particularly important if, for example, particular classes of vulnerable customers might be impacted disproportionately.
[89] This approval means that tariffs are not necessarily directly reflective of allowed revenues, but we make no allowance for that in this discussion as we do not consider it likely that the UR would take actions which had the effect of preventing NIE from recovering allowed revenues.

3.59 We discuss these issues in turn.

- *Uncertainty*

3.60 The UR and NIE are in disagreement over whether the Price Control Conditions continue to have legal effect. In practice, NIE acknowledged that it had acted as if it were bound by Price Control Conditions (see Appendix 2.5, paragraph 52). Moreover, some terms in the current Licence conditions are not defined for the period after March 2012. This means that suitable values or restrictions need to be inferred.

3.61 We think that the lack of formal definitions and specifications of important aspects of the price control algebra for the period from 1 April 2012 is not compatible with good administrative practice and may lead to further disputes between NIE and the UR in the future unless Licence modifications are made.

3.62 The consequence of these arrangements is that NIE, its investors, its customers, the UR and other stakeholders face considerable uncertainty over what price controls currently apply, how NIE should conduct itself, and what price controls will apply in the near future. We consider this situation to be against the public interest, for example because NIE cannot plan or invest appropriately, customers face uncertainty, and further disputes could increase costs.

3.63 One consequence of this uncertainty is that NIE has restrained its capital expenditure as outlined in Appendix 2.5, paragraph 52. It said that this was maintained at the minimum level consistent with compliance with its statutory and Licence obligations. This level is likely to be different from levels of efficient capital expenditure which we would consider to be in the public interest. For example, reduced investment might lead to higher risks of supply failure, less network development, inefficient long-run investment decisions and so on.

- *Aspects of the price control design are not sufficient to protect the interests of consumers*

3.64 We have provisionally determined that aspects of the design of the system for setting allowances and remunerating opex and capex operate against the public interest.

3.65 The calculation of NIE's maximum regulated revenue according to the level of capital expenditure that NIE incurs may expose consumers to excessively high charges that reflect capital expenditure that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to network investment. We have provisionally determined that the public interest is better served by systems which, compared with cost pass-through, better incentivize NIE to enhance the efficiency of its capital expenditure.[90] In consequence, new capex allowances need to be set.

3.66 Another way in which cost pass-through for capex could also operate against the public interest, because it may expose customers to unnecessarily high charges, arising from the possibility for NIE's sister company, NIE Powerteam, to charge inappropriately high charges to NIE for the work it carries out on NIE's network.

3.67 We consider that where the incentive rates for outperformance differ between opex and capex, this can create distortions in how NIE would organize its activities that could increase inefficiencies. In particular, under the RP4 price controls, the separate allowance schemes in relation to opex and capex provides NIE with unduly strong financial incentives to adopt working practices that favour capex-intensive practices over opex but which may not be efficient. This is because NIE would expect its opex allowances to be unchanged within the price control period but for it to be able to pass through higher capex costs (on which it will continue to earn a return from the

[90] Our view is that the special capital efficiency incentive schemes for labour productivity and capital efficiency included as part of the licence conditions are not sufficient to address this risk.

RAB). This would result in inefficient practices and so expose consumers to excessively high charges.

3.68 In addition, the interaction of the opex and capex arrangements may lead to excessively high charges on consumers if NIE changes its working practices or accounting practices over time so as to reclassify opex as capex, even where its activities remain essentially unchanged. Changes in capitalization practices could lead to activities notionally funded through an opex allowance also being funded through capex.

3.69 We consider that a benchmarking approach (ie setting opex allowances with reference to the costs of efficient comparators) provides a stronger incentive to operate efficiently than the incentives on opex efficiency under the RP4 controls. We have also identified that opex allowances should be adjusted for efficient indirect costs. In consequence, we have applied the benchmarking and indirect adjustment approach to allowances to opex allowances and other associated items, including revision of pension arrangements. Our provisional determination is that the current arrangements are against the public interest when this superior alternative is available.

3.70 In addition, specific opex allowances need to be set for new, additional functions and items of opex that NIE has to be able to finance to achieve necessary functions.

3.71 Additionally, the calculation of NIE's maximum regulated revenue according to the level of 'uncontrollable' operating costs that it incurs may expose consumers to excessively high charges that reflect excessive expenditure on items treated as uncontrollable costs which NIE nonetheless has some influence over. We have found that this applies to some such costs which can be reclassified as wholly or partially controllable, and therefore the current price control conditions operate against the public interest in this regard.

- *Excess cost of capital*

3.72 As outlined in Section 13, we provisionally determine that the current allowance for the cost of capital in the price control conditions is too high, which may expose consumers to excessively high charges.

- *RAB*

3.73 We note that investments are currently added to a 40-year RAB. We have provisionally determined that this operates against the public interest for significant expenditure on assets which have a much shorter life. We consider that this applies to tree cutting, because in our view it is inappropriate for future generations to be paying the costs of investments which have such a short life in relation to the period over which they are being depreciated for pricing purposes (40 years). We also consider that certain non-network capex investment (largely covering IT) should also be placed in a short-term RAB rather than expensed.

Information reporting and transparency and the public interest

3.74 Our terms of reference also require us to consider whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences.

3.75 As explained in Section 17, we have provisionally determined that the continuation of the existing Licence absent further conditions will operate against the public interest. This is because we have found that the UR currently receives insufficient reliable information in order for it to regulate NIE in a fully effective manner. Other stakeholders (such as consumer representatives) may also benefit from greater transparency and thus be better placed to influence conduct and regulation. Moreover, in order for the UR and other stakeholders to be able to make the most effective use of this information, it needs to be prepared in a format that is comparable to information available from the GB DNOs. This is so that the UR can, in particular, take views on the appropriateness of NIE's requests for allowances, and so that the UR can more effectively benchmark NIE's unit and overall costs. In the absence of such information, we consider that there is a risk that regulation will not be fully effective, which may result in customers being charged more than is needed, it may mean that NIE does not maintain suitable levels of service or certain categories of customers are disadvantaged, and it may mean that NIE might not be properly funded for certain activities or may face uncertainty over how it will be treated in the future by the UR.

Observations on redundant terms

3.76 We have identified several terms that have existed under the RP4 price control arrangements that we think are redundant or will become redundant under the revisions to the price control that we have proposed. While we do not consider that their existence within RP4 operates against the public interest (which is the first question we need to answer), in the context of determining how the price control conditions may be revised to address the adverse effects, we consider that in consequence their retention will operate against the public interest when these other changes are made. This is because redundant conditions are likely to create uncertainty over whether, or when, they might be used, whereas we consider that regulation works most effectively, and firms are able to operate most efficiently, where there is regulatory clarity. The terms in question, as described in paragraphs 5.350 to 5.358 are:

- the Powerteam profit-sharing term (PPS_t);

- the revenue cap implemented through the PC_t term (and the related RRF_t term); and
- provision (viii) under D_t term (this term provides for the maximum regulated revenue to be adjusted to allow for additional costs approved by the UR).

Structure of the rest of the provisional determination document

3.77 We have found that the Price Control Conditions in each Licence operate or may be expected to operate against the public interest. In the following sections we consider whether the effects adverse to the public interest which those matters have, or may be expected to have, could be remedied or prevented by modifications of the Conditions of each Licence (see paragraph 1.1). In particular:

- Section 4 considers issues regarding the timing of any modification to the Licence conditions;
- Section 5 considers high-level issues relating to the design of a future price control mechanism to ensure that NIE has incentives to be efficient;
- Section 6 considers the possible introduction of incentive mechanisms relating to NIE's performance;
- Section 7 provides an overview of our projections of NIE's efficient costs in RP5;
- Section 8 is concerned with indirect cost benchmarking (to ensure that NIE has incentives be efficient);
- Section 9 sets out our views of NIE's necessary core network investments;
- Section 10 details other elements of our cost assessment;
- Section 11 discusses relative price effects and likely productivity gains in RP5;
- Section 12 sets out our treatment of NIE's pension arrangements;
- Section 13 details our view of NIE's allowable rate of return on its RAB in RP5;
- Section 14 discusses certain issues between NIE and the UR that are unresolved regarding the operation of the current Licences in RP4;
- Section 15 is concerned with issues relating to NIE's capitalization practices;

- Section 16 contains our assessment of whether our provisional determination would allow NIE to finance its operations;
- Section 17 contains our view of the UR’s proposal to introduce a reporter and further transparency requirements on NIE; and
- Section 18 sets out a summary of our determination.

4. Timing and duration of a new price control

4.1. In light of our assessment in Section 3 that NIE's current licence conditions operate against the public interest, we consider that licence modifications are required to introduce a new price control (or revenue control). We propose that the new price control governs the calculation of NIE's tariffs applicable from 1 October 2014 onwards. This section discusses several issues relating to the timing and duration of our proposed new price control.

4.2. In addition, we consider that separate licence modifications are required to address the fact that, in the period since 1 April 2012, there has been ambiguity and doubt as to whether the current licence conditions impose a legally enforceable restriction on NIE's prices or revenues and how any such price or revenue restriction should be calculated. We propose modifications to resolve such ambiguities.

4.3. This section is structured as follows:

(a) we explain our proposal for the new price control to start from 1 October 2014;

(b) we explain our proposal for the new price control to have a planned end date of 30 September 2017;

(c) we describe our proposal to make licence modifications to clarify the restriction on NIE's maximum regulated revenue in the period between 1 April 2012 and 30 September 2014;

(d) we describe and explain our proposal to make adjustments as part of the calculation of the new price control from 1 October 2014 to provide some compensation to consumers or NIE in relation to deficiencies in the calculation of NIE's maximum regulated revenue and tariffs in the period between 1 April 2012 and 30 September 2014;

(e) we explain our proposals for price control licence conditions after the planned end date; and

(f) we consider potential changes to the financial year for price control licence conditions and regulatory reporting.

4.4. The start date in paragraph 4.3*(a)* above refers to the date at which the licence modifications that implement our final determinations would first affect NIE's tariffs. We propose that the calculation of the new price control applicable from 1 October 2014 also takes account of our assessment of NIE's efficient expenditure requirements and financing costs in the period between 1 April 2012 and 30 September 2014. This aspect of our proposals is discussed in more detail under paragraph 4.3*(d)* above.

Start date and regulatory financial year

4.5. NIE currently sets new tariffs each year, which take effect on 1 October. NIE has already set the tariffs applicable from 1 October 2013 to 30 September 2014. Unless changes are made to NIE's tariff-setting process, the earliest date at which our determinations can affect NIE's tariffs is 1 October 2014.

4.6. Changes to NIE's tariff setting process to allow an earlier effect on tariffs would be disruptive. There are also benefits to suppliers and consumers from advance notice of any significant tariff changes.

4.7. We therefore propose that the start date for the new price control is 1 October 2014.

Duration and planned end date

4.8. The UR proposed a new price control with a planned end date of 30 September 2017. NIE told us it was content that the new price control should run until 30 September 2017.

4.9. We propose that the planned end date for the new price control is 30 September 2017. This date is consistent with the submissions of the parties. It also reflects two practical considerations, which we discuss in more detail below:

(a) preparations for the next price control review for NIE; and

(b) availability of information on expenditure forecasts.

Preparations for the next price control review for NIE

4.10. If we set a shorter price control period, there would be less time available to the UR and NIE for preparation for the next price control review.

4.11. NIE and the UR will need time to develop and apply effective annual cost reporting arrangements that are aligned with the cost reporting framework for the GB DNOs. Further, if they want the next price control to reflect Ofgem's output-based approach, NIE and the UR will need to establish reporting on measures of asset health and risk. There is a risk that such an approach cannot be introduced at the next price control review because reliable data are not yet available. At the hearing, NIE indicated that it did not expect to be able to report information on asset health until around 2016 or 2017.

Availability of information on expenditure forecasts

4.12. Another practical consideration in determining the planned end date for a new price control is the availability of forecasts of NIE's expenditure requirements—as well as review and assessment of those forecasts.

4.13. As part of price control processes, a regulator would typically be expected to determine the duration of the price control before asking the regulated company to prepare expenditure forecasts over that period. The price control review for NIE was originally planned on the basis that a new price control would run from 1 April 2012 to

31 March 2017. The expenditure forecasts that NIE originally submitted to the UR as part of its BPQ responses were prepared on that basis.

4.14. Following delays to the process, the UR subsequently proposed a new price control that would apply over the 4.75-year period from 1 January 2013 to 30 September 2017. The UR's calculation of price control proposals for the 4.75-year period reflected a different approach for operating expenditure and capital expenditure.

4.15. For operating expenditure (and pensions), the UR's price control proposals were calculated by first determining an allowance for a five-year period and then scaling this allowance down by a factor of 4.75/5 to determine an allowance for a 4.75-year period.

4.16. For capital expenditure, the UR's price control proposals were calculated on the basis of its determination of a capital expenditure allowance (subject to its proposed incentive and adjustment mechanisms) for the five-year period from 1 October 2012 to 30 September 2017. The UR took the aggregate expenditure allowance for the five-year period and allocated this between five 12-month periods between 1 October 2012 and 30 September 2017. The UR used these annual allocations of the capital expenditure allowance in the following way:

(a) For the period 1 October 2012 to 31 December 2012, the UR proposed that NIE's actual capital expenditure would be added to its RAB in line with the RP4 treatment of capital expenditure.

(b) For the period from 1 January 2013 to 30 September 2013, the UR proposed that NIE's allowance for capital expenditure would be equal to the capital expenditure allowance the UR allocated to the period from 1 October 2012 to 30 September 2013 minus NIE's actual capital expenditure (subject to this being efficiently incurred) in the period 1 October 2012 to 31 December 2012 (see *(a)* above).

(c) For each 12-month period from 1 October 2013 onwards, the UR proposed that NIE's allowance for capital expenditure would be equal to the capital expenditure allowance that the UR allocated to that 12-month period.

4.17. NIE's Statement of Case does not define clearly the period over which its expenditure forecasts apply. It refers at various points to forecasts during 'RP5' but does not define precisely what this means. Because of delays to the UR's price control process, the term 'RP5' is ambiguous. The UR originally intended the RP5 period to run from 1 April 2012 to 31 March 2017; but the UR's final determinations for RP5 proposed a price control period from 1 January 2013 to 30 September 2017 with an allowance for capital expenditure based on the UR's assessment of NIE's expenditure requirements for the five-year period from 1 October 2012 to 30 September 2017.

4.18. NIE has not sought to revise its RP5 expenditure forecasts in light of changes to the time frame over which the UR's proposed RP5 period would apply (eg the UR's revised end date of 30 September 2017).[1]

4.19. On the basis of the forecasts and other information available it seems feasible for us to determine a price control with a planned end date of 30 September 2017. In contrast, an end date significantly later than 30 September 2017 would require further forecasts to be prepared and reviewed.

[1] For instance, in Annex 5A.2 of its Statement of Case, NIE provided a reconciliation between its 'latest assessment of its capex requirement for RP5', its capital expenditure forecast from its BPQ (which was for the five-year period from April 2012) and the UR's final determinations. NIE did not identify any differences between its latest expenditure forecast and its original BPQ forecast on account of changes to the duration and start date of the price control.

Maximum regulated revenue for period from 1 April 2012 to 30 September 2014

4.20. We have proposed that a new price control would be implemented with effect on the calculation of tariffs from 1 October 2014. As discussed above, this represents the first practical date at which our determinations can affect the tariff-setting process.

4.21. In addition, we consider it necessary to modify NIE's licence conditions in relation to the formulae used for the calculation of NIE's maximum regulated revenue in the period from 1 April 2012 to 30 September 2014. This is for two related reasons:

(a) Without modification, there would remain uncertainty in the period to 1 October 2014 as to whether NIE faces an enforceable revenue control and how any such revenue control should be calculated. This is because some elements of the formulae used to calculate NIE's maximum regulated revenue are not defined or specified for the period from 1 April 2012. We do not consider it appropriate to leave this uncertainty unresolved.

(b) The calculation of NIE's maximum regulated revenue in the existing price control conditions includes a revenue correction factor: the KD_t term. The effect of this term is to adjust NIE's maximum regulated revenue in light of any under- or over-recovery of revenue in relation to its maximum regulated revenue in the previous financial year. We envisage the retention of this revenue correction factor for the new price control that would be used to calculate tariffs from 1 October 2014. If there is uncertainty about the calculation of the maximum regulated revenue in the period before 1 October 2014 reflecting from point *(a)* above, there could be practical problems and disputes in the calculation of NIE's maximum regulated revenue and the approval of tariffs for the period from 1 October 2014.

4.22. With regard to the calculation of maximum regulated revenue in the period to 30 September 2014, we propose to limit any licence modifications to the minimum changes necessary to ensure that all terms required to calculate the restrictions on

NIE's revenues are defined for the period from 1 April 2012 onwards. In doing so, we will define terms in a way that is as consistent as possible with the other terms that do exist in the licence, drawing on the views of the parties.

4.23. The current licence conditions require that 'in setting its transmission and distribution charges' NIE must use 'its best endeavours to ensure that in any relevant year the regulated transmission and distribution revenue shall not exceed the maximum regulated transmission and distribution revenue' (Annex 2, paragraph 2). NIE proposed that in respect of the period before 1 October 2014, for which it has already set tariffs, we should remove the obligation for NIE to use its best endeavours to ensure that regulated transmission and distribution revenue shall not exceed the maximum regulated transmission and distribution revenue.

4.24. We agree with NIE's proposal. As explained above, we do not intend to affect NIE's tariffs before 1 October 2014. It seems inappropriate to subject NIE to an obligation to use its best endeavours to ensure that before 1 October 2014 its maximum regulated revenue does not exceed an amount specified in the licence modifications resulting from our determination. We therefore propose licence modifications that specify a maximum regulated revenue for the period before 1 October 2014 without the best endeavours obligation in that period. The maximum regulated revenue specified will be used for the purpose of calculating the revenue correction factor (K_{Dt}) for the period from 1 October 2014, at which point NIE's best endeavours obligation will resume.

4.25. NIE also proposed that we should also make licence modifications in respect of the period before 1 October 2014 to resolve disputes between the UR and NIE concerning the interpretation or application of certain terms in the current licence conditions.

NIE argued that it would be inefficient and contrary to the public interest to leave such terms in place for the period up to 30 September 2014.

4.26. We do not consider such changes to be necessary in relation to the period between from 1 April 2012 to 30 September 2014. We do not envisage our licence modifications affecting tariffs before 1 October 2014. As discussed in more detail in the sub-section below, we are proposing licence modifications affecting the calculation of tariffs from 1 October 2014 which would involve adjustments for differences between *(a)* the maximum regulated revenue for the period from 1 April 2012 to 30 September 2014 specified in the licence and *(b)* our assessment of what maximum regulated revenue for that period 'ought' to have been. These adjustments should have the effect of cancelling out the impact of any differences between actual revenue in the period from 1 April 2012 to 30 September 2014 and maximum regulated revenue in the period from 1 April 2012 to 30 September 2014—thereby neutralizing the impact of alternative interpretations of any disputed terms in the licence for the period from 1 April 2012 to 30 September 2014.

4.27. We consider in Section 14 whether to make licence modifications in respect of disputes between NIE and the UR relating to the interpretation of licence conditions in the period before 1 April 2012.

Adjustments to price control from 1 October 2014 for revenue since 1 April 2012

4.28. The licence modifications suggested in paragraphs 4.21 and 4.22 can be seen as regulatory housekeeping to address the fact that some elements of the formulae used to calculate NIE's maximum regulated revenue are not defined or specified for the period from 1 April 2012.

4.29. As a separate matter, we propose licence modifications that would aim to protect the interests of consumers and NIE against other potential shortcomings and deficiencies of the RP4 price control arrangements. Besides the lack of explicit definitions for some elements of price control formulae, we have identified a number of other ways in which the current price control conditions, established as part of the RP4 price control, operate against the public interest (see paragraphs 3.52 to 3.73).

4.30. These features of the current price control are likely to have harmed consumers or NIE in the past, since they have fed through to the calculation of the tariffs that NIE has imposed and the revenues it has collected. They are also likely to harm consumers or NIE in the period to 30 September 2014.

4.31. We cannot change the tariffs that NIE has charged in the past. Nor do we propose that NIE revises the tariffs that it has already set for the period from 1 October 2013 to 30 September 2014. Nonetheless, we propose to mitigate or compensate for the harm that consumers or NIE have experienced in the past as a result of the application of the RP4 licence conditions beyond their intended end date. To do so, we propose to make adjustments as part of the calculation of NIE's maximum regulated revenue in the period from 1 October 2014 that are intended to compensate consumers or NIE in relation to the revenue restriction on NIE in the period between 1 April 2012 and 30 September 2014.[2]

4.32. Both parties expect us to determine licence modifications that give effect to this kind of adjustment. In its submissions, NIE has proposed that we should make licence

[2] As a simple illustration, we could create licence modifications with the following effects: *(a)* If we found that NIE has collected (and will collect) £X million too little revenue in the period before 1 October 2014, we could include an additional allowance in the calculation of the revenue restriction from 1 October 2014. This would provide some compensation for NIE for the shortfall in revenue in the period before 1 October 2014. *(b)* If we found that NIE has collected (and will collect) £X million too much revenue in the period before 1 October 2014, we could made a deduction for that amount in the calculation of the maximum regulated revenue from 1 October 2014. This would provide some compensation for consumers for high charges in the period before 1 October 2014. As discussed further below, any additional allowance or deduction calculated in relation to *(a)* and *(b)* above could be based on an assessment of NIE's (efficient) expenditure requirements and cost of capital in the period between 1 April 2012 and 30 September 2014.

modification so as to protect 'NIE's position in relation to the period from 1 April 2012'. The UR's submissions to us on the current price control and the public interest suggest some aspects of the calculation of a new price control (eg the WACC term) could apply from 1 April 2012 with other elements applicable from 1 January 2013. Neither party suggested that a new price control should be introduced at a date subsequent to our final determinations which is calculated in a way that ignores the amount of revenue that NIE has been permitted to collect in the period before that date.

4.33. For the purposes of calculating revenue adjustments, we propose to use the same interest rate or discount rate as used for the correction factor in the current licence conditions (K_{Dt} term). The UR has identified the possibility of using the WACC as an alternative discount rate for these purposes, but we have found no reason to use a different discount rate as for the correction factor in the current licence conditions.

4.34. In order to calculate the magnitude of an adjustment, we need to assess what revenue NIE 'ought' to have collected, which can then be compared with the revenue that NIE is entitled to collect in the period to 30 September 2014 under the RP4 licence conditions (as amended under the proposals above to address any missing terms in price control algebra). The adjustment is intended to compensate NIE or consumers, where possible, for any harm arising from features of the RP4 price control that operate against the public interest. We propose to assess what the maximum revenue restriction 'ought' to have been in light of:

(a) an assessment of NIE's (efficient) operating and capital expenditure requirements for the period from 1 April 2012 to 30 September 2014. These can draw on the same cost assessment methods we use for the period from 1 October 2014 onwards, supplemented where appropriate with available out-turn expenditure data (eg for the period 1 April 2012 to 31 March 2013);

(b) an assessment of the appropriate price control funding for pension contributions; and

(c) an estimate of NIE's WACC for the period from 1 April 2012 to 30 September 2014. Whether the same value of WACC is used as for the period from 1 October 2014 onwards would depend on aspects of the method used to determine the WACC from 1 October 2014 (eg the extent to which estimates of the risk-free rate in a CAPM calculation reflect only recent market information or market information over a longer-term historical time period).

4.35. That adjustment will be additional to the application of the existing correction factor K_{Dt} in the current licence conditions which adjusts NIE's maximum regulated revenue in one financial year according for differences between the *(a)* maximum regulated revenue in the previous financial year and *(b)* the revenue that NIE actually received from customers in the previous financial year.[3]

4.36. It would not be appropriate to make adjustments in relation to NIE's past performance under any new incentive schemes or obligations established as part of this inquiry, since incentives cannot affect historical performance.

4.37. We do, however, propose that the calculated adjustments reflect the application of the cost risk-sharing mechanism set out in Section 5. Whilst this arrangement might be viewed as part of our proposed incentive framework, its purpose and impact is not limited to NIE's financial incentives. It is intended to share between consumers and NIE's investors the financial impact of any differences between our assessment of NIE's efficient expenditure requirements and NIE's actual expenditure. That sharing is desirable in the period from 1 April 2012 to 30 September 2014 as well as in the period from 1 October 2014. Further, adopting a different approach to cost risk-

[3] For practical purposes in drafting licence conditions it may prove better to combine the two adjustments, but for the purposes of exposition here we keep them separate.

sharing before and after 1 October 2014 could create perverse incentives and unduly distort NIE's expenditure decisions.

4.38. We intend the adjustments to compensate NIE or consumers in relation to short-comings or deficiencies in the calculation of NIE's maximum regulated revenue in the period from 1 April 2012 to 30 September 2014. In the course of our inquiry we also considered the following:

(a) the possibility of making adjustments in relation to NIE's maximum regulated revenue in the period before 1 April 2012; and

(b) the possibility of limiting adjustments to the period from 1 January 2013.

4.39. We explain below our assessment of these points.

NIE's maximum regulated revenue in the period before 1 April 2012

4.40. In September 2006, the UR and NIE agreed a price control that was intended to apply 31 March 2012. It is clear that both NIE and the UR expected a new price control to take effect from 1 April 2012 but no sooner.

4.41. We have not identified a good reason to implement a new price control from 1 October 2014 that would undermine the financial basis of the 2006 price control agreement between NIE and the UR.

Adjustments limited to maximum regulated revenue from 1 January 2013

4.42. In its RP5 final determinations, the UR proposed a form of extension of the RP4 price control to 31 December 2012, with the UR's new price control arrangements taking effect from 1 January 2013.

4.43. If there had been agreement between the UR and NIE to apply something along the lines of the RP4 price control—with agreement on the missing terms—to the period from 1 April 2012 and 31 December 2012 this might provide a reason against making any adjustment to the price control from 1 October 2014 in relation to the revenue restriction before 1 January 2013. We found no such agreement. NIE rejected the UR's RP5 proposals and denies that there was any agreement between NIE and the UR for a new price control or a price control extension to cover the period from 1 April 2012 to 31 December 2012.

4.44. We have not identified any sound basis for treating the period between 1 January 2013 and 30 September 2014 differently to the period between 1 April 2012 and 31 December 2012.

Price control licence conditions after planned end date

4.45. Whilst we may determine a new price control for NIE which is intended to apply until the planned end date of 30 September 2017, there is no guarantee that NIE and the UR will agree on licence modifications to implement a replacement price control by that planned end date.

4.46. To avoid a repeat of the situation currently experienced, in which NIE argued that there has effectively been no functioning price control applicable since 1 April 2012, it is prudent to ensure that a price control applies to NIE after 30 September 2017.

4.47. The price control conditions that apply from 1 October 2017 should be seen as a form of interim price control before a new price control is established. This is necessary in the event of delays to the agreement of a new price control. When a new price control is determined—whether by agreement between the parties or determined by the CC—this could include adjustments in respect of the amount of revenue that NIE has collected in the period since 1 October 2017, to address any shortcomings of the interim price control applicable since 1 October 2017.

4.48. In the draft licence conditions published alongside its RP5 proposals, the UR proposed that the maximum regulated revenue for NIE for financial years from 2017/18 onwards should be calculated as the maximum regulated revenue in the previous financial year adjusted for RPI inflation.

4.49. An alternative option is that NIE's tariffs after the planned end date are restricted to no more than the maximum levels of each tariff set at the last formal tariff setting process before the planned end date (eg the tariffs introduced from 1 October 2016 if the planned end date is 30 September 2017). This option would be particularly simple which seems advantageous for the type of control envisaged above. Further, the imposition of a simple tariff control of this nature would more properly reflect the fact that we have not carried out the work necessary to determine an appropriate maximum revenue control for the period from 1 October 2017.

4.50. On this basis, we propose licence modifications with the effect that, in the period from 1 October 2017, the restriction on NIE's maximum regulated revenue is replaced with a prohibition on increases to the tariffs set from 1 October 2016.

4.51. NIE has pointed out that Northern Ireland legislation may be amended, as envisaged in the EU energy directives, to empower the UR to introduce a new price control from 1 October 2017 without NIE's consent. Nonetheless, NIE said that it would be content with the type of arrangement proposed above. We agree with NIE's view that potential changes to the UR's powers to make licence modifications without NIE's consent do not eliminate the need for some provision within NIE's licence conditions in relation to maximum revenues or prices in the period from 1 October 2017.

Financial year for price control licence conditions and regulatory reporting

4.52. The existing price control licence conditions for NIE work on the basis of a financial year that runs from 1 April to 31 March. NIE's regulatory accounts are currently also prepared for a financial year from 1 April to 31 March.

4.53. There are potential practical benefits in alignment between the financial year for price control purposes (ie the financial year to which algebra to calculate maximum regulated revenue apply) and the financial year for regulatory accounts and other annual regulatory reporting. This is because the price control calculations will draw on regulatory accounting and reporting information.

4.54. If a new price control applies from 1 October 2014 to 30 September 2017, one option would be to seek to change the financial year for regulatory accounts from 1 October to 30 September. However, whilst this would support alignment with the planned start and end date of the price control, and NIE's tariffs setting process, there are dis-advantages:

(a) The implementation costs and possible risks of inconsistencies from a change in reporting years.

(b) The introduction of an inconsistency between the reporting period for NIE and that for GB DNOs, which provide cost and other data to Ofgem for financial years that run from 1 April to 31 March.

4.55. The second of these points seems particularly important. We are proposing substantial changes to NIE's regulatory reporting framework to better align information on its costs with information on the costs of GB DNOs. This is intended to help regulatory cost assessment work at future price control reviews for NIE. If NIE's regulatory reporting year is not from 1 April to 31 March then this could reduce the comparability of NIE's costs with those of GB DNOs.

4.56. We raised the issues above with the parties. NIE said that a change in regulatory accounting year to run from 1 October to 30 September would be sensible and that it did not object to this. The UR said that it would like to consider the matter further and suggested that we consult on this matter in its provisional decision.

4.57. For our provisional determinations we do not propose any changes to the financial years for regulatory reporting. But, in line with the UR's suggestion, we welcome the views of stakeholders and will consider further for our final determinations.

5. Price control design

5.1 In Section 3 we established that the current price control for NIE is not in the public interest, and in Section 4 we considered certain timing and transitional issues concerning the introduction of a new price control. This section considers the design of the new price control. Price control design refers to the work to establish a new price control for NIE excluding the work to determine the numbers to calibrate or populate that price control, which we consider in Sections 7 to 16. This section is organized as follows:

(a) We provide an overview of the features of the current price control Licence conditions that operate against the public interest and which are most relevant to our work on price control design (paragraphs 5.4 to 5.9).

(b) We provide an overview of the type of price control framework we propose for NIE, which we describe as RAB-based incentive regulation. This will take the form of revenue controls on NIE, with separate revenue controls for transmission and distribution (paragraphs 5.10 to 5.23).

(c) We highlight some risks that arise under RAB-based incentive regulation that are relevant to decisions across several aspects of price control design (paragraphs 5.24 to 5.32).

(d) We summarize the UR's proposals for the design of a new price control for NIE and NIE's submissions on the design of a new price control (paragraphs 5.33 to 5.43).

(e) We consider in more detail a series of different aspects of price control design. We review the parties' submissions and discuss risks and concerns relevant to the public interest. In some cases we set out alternative options that we have identified (paragraphs 5.44 to 5.359).

5.2 Price controls may also include specific rules, obligations or financial incentives in relation to the regulated company's quality of service. These features of price control design are considered separately in Section 6. Section 6 also considers the treatment of NIE's revenues from revenue protection activities.

5.3 In the course of our work on price control design, we have taken account of the RAB-based price control frameworks applied by other UK regulators, including Ofgem, Ofwat and the CAA. The limited time frame available for our inquiry, and the nature of the work to date by the UR and NIE, mean that we face constraints as to the feasible options available for the design of a new price control for NIE. We do not, in particular, consider it feasible to apply—or retrofit—Ofgem's RIIO price control framework in full to NIE as part of this inquiry. Ofgem's RIIO framework is complex, with many different elements. The implementation of Ofgem's approach requires a lengthy time frame.[1] Nonetheless, we have considered the potential application of particular aspects of Ofgem's approach as part of our work where practical and in light of submissions made to us as part of our inquiry.

The current Licence conditions and the public interest

5.4 In paragraphs 3.58 to 3.75 we set out aspects of the current RP4 price controls which we provisionally consider to operate against the public interest. Of particular relevance to this section are our findings in relation to 'aspects of the price control design are not sufficient to protect the interest of consumers'. We note here why these operate against the public interest.

5.5 First, as noted in paragraph 3.65, the calculation of NIE's maximum regulated revenue according to the level of capex that NIE incurs may expose consumers to excessively high charges that reflect capex that was inefficiently or unnecessarily incurred by NIE—or missed opportunities for efficiency and innovation in relation to

[1] In September 2012 Ofgem published an extensive consultation paper on its review of new price controls for the GB electricity distribution companies that will come into effect in April 2015.

network investment. Therefore we consider it necessary to better incentivize NIE to enhance the efficiency of its capex—see, for example, paragraphs 5.91 to 5.113.

5.6 Another way in which cost pass-through for capex could also operate against the public interest, because it may expose customers to unnecessarily high charges, arises from the possibility for NIE's sister company, NIE Powerteam, to charge inappropriately high charges to NIE for the work it carries out on NIE's network (see paragraph 3.66). This is noted in relation to the Powerteam profit-sharing term in paragraph 5.353.

5.7 We consider that where the incentive rates for outperformance differ between opex and capex, this can create distortions in how NIE would organize its activities that could increase inefficiencies. In particular, under the RP4 price controls, the separate allowance schemes in relation to opex and capex provides NIE with unduly strong financial incentives to adopt working practices that favour capex-intensive practices over opex but which may not be efficient. In paragraphs 5.90 to 5.99 we discuss aspects of cost risk-sharing mechanisms, including proposals for alignment of cost risk-sharing across opex and capex. Where common incentives apply to both opex and capex, we would expect the incentives that are likely to favour adoption of capex-intensive practices to be reduced or eliminated.

5.8 In addition, the interaction of the opex and capex arrangements may lead to excessively high charges on consumers if NIE changes its working practices or accounting practices over time so as to reclassify opex as capex, even where its activities remain essentially unchanged. Changes in capitalization practices could lead to activities notionally funded through an opex allowance also being funded through capex. This capitalization practices effect is discussed in Section 15.

5.9 Additionally, the calculation of NIE's maximum regulated revenue according to the level of 'uncontrollable' operating costs that it incurs may expose consumers to excessively high charges that reflect excessive expenditure on items treated as un-controllable costs which NIE nonetheless has some influence over. We have found that this applies to some such costs which can be reclassified as wholly or partially controllable, and therefore the current price control conditions operate against the public interest in this regard. Examples of where this could be a relevant factor are discussed in paragraphs 5.298 to 5.349.

Type of price control for NIE

5.10 We can distinguish, in broad terms, between three different types of price or revenue control that might be set for NIE:

(a) *RAB-based incentive regulation.* Under this type of regulation, we would make forecasts of NIE's (efficient) expenditure requirements over a defined price control period, across both opex and capex, and use these as the basis to set a revenue control for NIE's relevant distribution and transmission services. The forecasts of NIE's capex would feed into NIE's RAB. The revenue control would be calculated to provide NIE with sufficient revenue (but no more) to enable it to cover its operating costs (including depreciation on the RAB) and to earn a fair rate of return on its RAB. The price control would be designed in a way that is intended to provide NIE with financial incentives to operate efficiently and to avoid unnecessary expenditure, whilst also taking account of the difficulties of forecasting NIE's costs. The price control might include various mechanisms and arrangements to adjust NIE's revenue control and RAB in light of factors such as: its out-turn expenditure; measures of its service quality; measures of the volume of work it carries out; and additional costs approved by the regulator. The current NIE price control may be seen as a form of this type of regulation.

(b) *Cost pass-through subject to efficient spend clause.* NIE would be required to set charges that allow it to cover its reasonable costs of providing the relevant distribution and transmission services and to earn a reasonable rate of return on the value of its assets. The rate of return would be set by reference to a WACC determined by the CC. NIE's entitlement to recovery of costs through charges to consumers would be conditional on an inefficient spend clause under which the regulator would be able to make an adjustment to NIE's revenue control and RAB to ensure that consumers are not exposed to specific costs that the regulator reasonably finds to be inefficient or wasteful.

(c) *Price of a hypothetical competitive supplier.* The CC would determine a price control that places restrictions on specific charges for use of NIE's electricity distribution and transmission systems. These would be calculated by reference to a model of the costs of a hypothetical efficient network operator. The model would calculate (maximum) tariffs for different types of electricity consumer, drawing on information about the costs of providing services and the different demands that different types of consumers place on the network. The model would be calibrated to reflect aspects of NIE's distribution and transmission services such as: the number of electricity consumers connected to the distribution and transmission systems; the scale and time profile of their electricity consumption or generation; and physical properties of these systems such as the length of lines at different voltage levels and the proportion which are overground rather than underground.

5.11 The new price controls proposed by the UR and NIE both fall under the type in paragraph 5.10*(a)*. We have also focused our work on price control design on this type of price control.

5.12 We propose RPI indexation of the revenue controls for NIE, as under the current Licence conditions.

5.13 We did not consider that an approach involving cost pass-through subject to efficient spend clause would provide sufficient protection to consumers against the risks that the charges they face are too high because of inefficient expenditure or missed opportunities for efficiency improvements.

5.14 We considered that a change to a price control based on the price of a hypothetical competitive supplier would represent a major change in the price control framework for NIE—and one that might be difficult to undo. In particular, a price control based on the price of a hypothetical competitive supplier would not be compatible with the existing regulatory treatment of NIE's RAB, which has implications for the level of prices faced by consumers and the risks faced by investors. We did not consider that such a change was proportionate or practical for the purposes of our inquiry.

Separate revenue controls for transmission and distribution

5.15 There are now separate Licences for NIE's electricity transmission network (which operates at 110 kV and 275 kV) and NIE's lower-voltage distribution network. We propose separate revenue controls for transmission and distribution, in line with the separate Licences.

5.16 NIE's business and accounting are not separated between transmission and distribution. Some allocation of costs between transmission and distribution will be required where these are not separately identified as either transmission or distribution costs.

5.17 Apart from consistency with the separation of Licences, separate revenue controls can help better align transmission charges with transmission costs and distribution charges with distribution costs. For example, major new transmission investment projects should not be funded through electricity distribution use of system charges, but there is a risk of this occurring if there is a single revenue control across transmission and distribution (especially if combined with a charging methodology that allocates a fixed percentage of revenues between transmission and distribution).

Revenue controls and restrictions on specific prices

5.18 The price control Licence conditions which are the subject of our reference take the form of a restriction on NIE's total revenues (excluding revenues from specified excluded services). These Licence conditions do not determine maximum prices for specific services.

5.19 We have identified a question as to whether such a control is sufficient to protect consumers from the risks of excessive charges for specific services. A control on aggregate revenues does not on its own ensure that charges for specific services or charges for specific types of consumers are reasonable. However, where controls on revenues (or weighted averages of prices) are applied they can be combined with other forms of regulation that affect the charges or tariffs for specific services or groups of electricity consumers.

5.20 Ofgem's regulation of the use of system charges for electricity distribution network companies in GB combines controls on aggregate revenues (Ofgem calls this the price control) with licence requirements for companies to set charges using a very detailed charging methodology that is common across the companies. Ofgem approved the charging methodology and was involved in its development.

5.21 There is no similar arrangement in Northern Ireland. NIE does not have a charging methodology that is comparable with that of the electricity distribution network companies in GB in terms of level of detail or transparency.

5.22 NIE's charges are the subject of an approval process by the UR. This process provides an opportunity for the UR to provide protection to consumers against the risks of excessive charges for specific services. We have not sought to review the effectiveness of that process. If there are public interest concerns about the risks of excessive charges for specific services, we believe that these could be addressed as part of the UR's powers through that process rather than through changes to price control licence conditions. We did not consider it practical in the time frame of our inquiry to develop a detailed charging methodology for NIE that could be specified in the price control Licence conditions.

5.23 The UR's tariff approval powers and the current tariff approval process are not part of the price control Licence conditions that are the subject of our inquiry. We did consider whether the existence of the UR's tariff approval powers may make the price control Licence conditions redundant. We do not believe this to be the case. We do not consider that the existence of this tariff approval process fully mitigates the adverse public interest effects of NIE's current price control licence conditions. Nor do we consider that it would be in the public interest to seek to address those effects by removing the restriction on NIE's maximum regulated revenue altogether and relying entirely on the UR's tariff approval powers. That would be a major change to the regulatory regime in which NIE operates. It would create considerable uncertainty for NIE's investors and it would not obviously benefit consumers. It also would remove the opportunity for the CC to determine a series of important issues that matter to the regulation of NIE's charges which have been disputed between NIE and the UR.

Risks relevant to price control design

5.24 We now highlight some risks that arise under RAB-based price control regulation that are relevant to decisions across a number of different aspects of price control design.

5.25 Within the category of RAB-based incentive regulation, a hypothetical simple price control for NIE would involving setting a maximum revenue allowance for the years of the price control period based on regulatory forecasts of NIE's expenditure requirements (if it were run efficiently) over that period. The Licence conditions for NIE would restrict NIE's revenue (other than for excluded services) to no more than that amount. The subsequent price control could be set in a similar way, with fresh forecasts of NIE's expenditure requirements and no adjustments to NIE's RAB or maximum revenue calculation for any differences between previous regulatory expenditure forecasts and NIE's actual expenditure. This hypothetical simple revenue control is a useful reference point, but contains two risks in particular: expenditure forecasting risks, and risks of inefficiency or over-investment to the detriment of consumers. We consider them in turn.

Expenditure forecasting risks

5.26 Most of the aspects of price control design that we consider in this section concern potential modifications which might be made to that hypothetical simple price control. In most, if not all, cases, the potential justification for these modifications is that they may address or reduce one of the following problems:[2]

(a) *The difficulty of making accurate forecasts.* Any expenditure forecast over a five-year period is uncertain. Both consumers and NIE would be financially exposed to the regulatory forecast or cost assessment. If the regulator (or CC) over-estimates NIE's (efficient) expenditure requirements, this could result in charges that are more than necessary for NIE to provide its services and comply with its

[2] The second problem might be seen as subset of the first.

legal obligations. If the regulator underestimates NIE's (efficient) expenditure requirements, this could deny investors a fair return on capital and/or prevent NIE from financing its activities. There is also a practical issue: making expenditure forecasts that a regulator can reasonably use as part of the calculation of a price control can be a time-consuming process.

(b) *The opportunity to defer planned investment projects to the detriment of consumers.* Even if we make reasonable forecasts of an efficient level of expenditure for NIE over the price control period, it may be possible for NIE to spend substantially less than this amount by deferring (or cancelling) some investment projects that, whilst worthwhile, are not essential within the price control period for the company to provide services to consumers, meet network design and planning standards or to meet legal obligations. Such opportunities might operate against the interests of consumers (as in effect they pay for projects that are not undertaken as planned and may subsequently face further charges to cover the costs of projects when they are carried out).

5.27 The potential modifications described in this section may bring their own problems and risks which need to be considered alongside their ability to mitigate the problems above (paragraph 5.26). In some cases, there may be concerns that the cure is worse than the problem. Nonetheless, many of them are familiar features of RAB-based price controls set by UK regulators including the UR, Ofgem and Ofwat.

Risks of inefficiency or overinvestment to the detriment of consumers

5.28 Depending on the design of a price control, there are risks that it harms the efficiency of the regulated company in a way that is ultimately to the detriment of consumers. In particular, some regulatory arrangements that are intended to limit the risks highlighted above in relation to expenditure forecasts and deferral of planned capex projects may lead to inefficient expenditure or unnecessary investment.

5.29 The aspects of price control design considered in this section may affect the financial incentives and opportunities that the regulated company has to identify and take opportunities to operate more efficiently. If the price control design is such that the revenues raised from consumers are adjusted (to some degree) in light of the company's actual expenditure, such adjustments will expose consumers to any inefficient decisions of the regulated company. Further, there are risks that any inefficiency feeds through to higher charges to consumers in the future if the price control determination at subsequent price control reviews is based, in part, on the level of costs it has incurred in the past.

5.30 Aspects of a price control may mean that there are limited profit opportunities available to the regulated company from cost savings, delivery of investment projects efficiently and avoiding unnecessary expenditure. There may also be a limited opportunity for a third party to profit from takeover of the regulated company and the implementation of new working practices. Limiting incentives for NIE to become more efficient may not be in the interests of consumers.

5.31 The price control may also provide the regulated company with opportunities to profit from doing things which are inefficient. For instance, the price control (and wider regulatory framework) may treat different categories of expenditure differently in a way that provides a financial incentive for the company to distort its expenditure away from what would otherwise be an efficient way of running the business.

5.32 Which risks apply, and their likely scale, will depend on the details of the price control design and also the regulated company's perceptions about current and future regulation. We have taken account of these general considerations as part of our work on the more specific aspects of price control design considered below.

Overview of main parties' submissions

5.33 This section provides an overview of the main parties' proposals and submissions on price control design. We mainly focus in this section on the UR's proposals from its RP5 final determinations and NIE's Statement of Case. Over the course of the inquiry the parties have made further submissions and proposals on specific aspects, partly in response to our work; we discuss these in the more detailed sections that follow.

5.34 Our overview of the main parties' submissions provides context for our work on price control design and highlights some of the issues that these parties considered most important to our inquiry. Nonetheless, we have not restricted our work on price control to the issues raised by the parties. And some of our proposals represent alternative options that we consider more appropriate than those submitted by the parties.

UR's proposals

5.35 Table 5.1 provides an overview of the UR's proposals for the design of a new price control for NIE. It focuses on some of the main differences between the UR's proposed treatment of different categories of NIE's expenditure. It does not capture some elements which are common across categories, such as the UR's proposals for an embedded reporter within NIE and for an efficient expend clause that would apply across NIE's capex.

5.36 More detailed information on the UR's proposals for capex is provided in Appendix 5.1.

TABLE 5.1 **Overview of the UR's RP5 proposals**

Category and features (not exhaustive)	*Expenditure coverage under UR's proposals*
Fund 1: output-measurable capital expenditure Upfront estimate of aggregate expenditure requirements based on forecast volumes and unit cost estimates NIE bears financial exposure for differences between its out-turn unit costs and UR's unit cost estimates (exposure through five-year delay to RAB adjustment for out-turn costs) Volume adjustment mechanism intended to deny NIE financial benefits from carrying out lower 'volume' of investment than forecast by UR at price control review; volume measure uses UR's unit cost estimates to assign weights to different types of activity or projects	• Transmission asset replacement • Distribution asset replacement
Fund 1: input-driven capital expenditure Upfront expenditure allowance, funded through RAB No adjustment to revenues or RAB for any differences between upfront allowance and out-turn expenditure	Capex relating to: • Fault and emergency work • Costs associated with replacing assets in storms • Reactive work • Capitalized overheads • Public realm work • Costs arising from new roads and street works legislation • Real price effects (RPEs) • ESQCR data collection and assessments
Fund 2 approach for specific load-related projects Some projects approved upfront by UR and estimate of their costs included in price control calculation Provision for UR to approve further projects during price control period, with estimated costs of such projects to be added to RAB at start of next price control review Provision for NIE to receive remuneration through RAB for investment that is not pre-approved by UR but which NIE can subsequently show was efficient NIE faces same financial exposure to its unit cost being different to UR's unit cost estimates as for output-measurable capex under Fund 1	• Expenditure on the distribution network to provide greater capacity to accommodate additional load
Fund 2 approach for metering capital expenditure Upfront forecast of costs used to calculate price control Adjustments for differences between forecast volumes and out-turn volumes based on upfront estimates of unit costs (volume driver mechanism)	• Costs of replacing and recertifying existing meters • Costs of installing new meters • Excludes smart meters
Fund 2 approach for connections capital expenditure Full cost pass-through	• Part of connection costs • Costs relating to certain network alterations
Capital expenditure fund 3 No upfront allowance used to calculate price control Provision for UR to approve further projects during price control period, with estimated costs of projects to be added to RAB at start of next price control review	• Projects to increase transmission and distribution system capacity and capability to accommodate renewable generation • Smart metering • Smart grid initiatives
Controllable operating expenditure Upfront allowance based on estimate of efficient expenditure requirement In the event of NIE underspend against upfront allowance, special incentive scheme applies—revenue adjustments made in future years intended to ensure NIE benefits from efficiency savings for five-year period (scheme based on Ofwat's historical operating expenditure incentive allowance) No financial adjustment or incentive scheme for overspend: NIE bears full exposure to its expenditure being above the upfront forecast during the price control period	• All opex with the exclusion of items specified under 'uncontrollable' operating expenditure below • Not defined by reference to specific activities or outputs
Uncontrollable operating expenditure Intended to pass through costs Price control calculated on basis of forecasts of NIE's costs for items within this category with adjustment for full difference between forecast and out-turn costs	• Rates • Wayleaves • Licence fees

Source: CC analysis.

NIE's proposals

5.37 NIE makes extensive criticisms of the UR's proposals for the design of a new price control.[3] Some relate to specific aspects of the proposals and are identified in the sections that follow. We highlight some of the more general points below:

(a) NIE claims that the approach in the UR's final determinations would lead it to follow a prescribed plan for its asset replacement programme which reflects the volumes of work and projects forecast at the price control review, rather than running its business efficiently in response to changing priorities over the price control period.

(b) Some of NIE's criticisms of the UR's proposals for capex are that it would diminish NIE's financial incentives to innovate and manage its network efficiently, and that it would involve micro-management by the UR.

(c) NIE argued that it would be subject to excessive regulatory risk from the wide scope for the UR (and the proposed reporter) to make ex-post assessments of its expenditure decisions which affect its maximum regulated revenue and the value of its RAB.

(d) NIE criticized the UR's proposals as ambiguous and not sufficiently well developed to be feasible.

5.38 NIE also argued that the UR's proposed approach to the treatment of capital departed from the traditional or established forms of 'RPI–X regulation'. We agree: the UR's proposals differ substantively from the types of RAB-base price controls set for energy network companies and companies in other sectors in the 1990s and early 2000s.

5.39 The fact that the UR's proposals represent a different regulatory approach from that taken for price controls set in the 1990s and early 2000s should not, in itself, be seen

[3] NIE Statement of Case, pp45–59.

as a valid criticism of the UR's proposals. In the past, the treatment of capex in RAB-based utility price controls has suffered from serious shortcomings which have been recognized by regulators other than the UR. Regulators such as Ofgem and Ofwat have sought to adapt their approaches over time to reduce the problems they have experienced. Ofgem's price control framework for energy network companies in 2013 differs extensively from its approach in 2003.

5.40 NIE clarified that its concerns with the UR's proposals were not so much that they involved changes in the regulatory regime, but with the nature of those changes and the overall philosophy towards price control regulation. NIE said that Ofgem's approach to regulation, which had evolved over time, had maintained a clear willingness on the part of the regulator to delegate management and operational decisions to the DNOs. With regard to the framework for energy network price controls (RIIO) that Ofgem established in 2010, NIE said:

> RIIO explicitly re-endorsed the incentive-based model as the right form of regulation and still envisages that incentives work best when the DNO is given a single ex ante allowance for forecast capex, and is left free to determine how best to spend the resulting revenues. This both creates substantial financial incentives for the DNO to beat the capex allowance by achieving year on year operational efficiency gains, and also leaves the DNO free to manage its response to changing network priorities.

5.41 NIE said that there was a regulatory philosophy in GB which attached substantial value to creating incentives for DNOs to respond dynamically and efficiently to changing priorities in their distribution businesses and an alternative regulatory philosophy, favoured by the UR, which did not attach such value. NIE considered the former philosophy better than the latter.

5.42 NIE in effect requested the CC to adopt the following approach for capex in relation to the UR's proposals:[4]

(a) Fund 1 should be limited to 'rolling programme' capital investments for which NIE could predict, with reasonably accuracy, both the need to replace set volumes of certain types of assets and the efficient cost per unit.

(b) The UR's proposals for Fund 2 should not be adopted.

(c) The UR's proposals for Fund 3 should be adopted, but with some modifications concerning the process for project approval and the categorization of which projects were included within Fund 3.

(d) The remainder of NIE's capex should be subject to what NIE referred to as a traditional or conventional RPI–X approach. An upfront expenditure allowance would be set and NIE would bear a set proportion of any underspend or over-spend relative to the upfront allowance. NIE proposed that it would face an incentive rate of 30 per cent, which would mean that around 70 per cent of variations between its actual expenditure and the regulatory forecasts should be passed through to consumers through adjustments to future charges and the RAB.

5.43 For opex, NIE proposed an upfront allowance for opex and a symmetrical efficiency incentive.[5]

Overview and structure of our proposals on price control design

5.44 The remainder of Section 5 considers in more detail a number of different aspects of price control design that we have provisionally determined. These are organized according to the structure set out in subsections below, which provides a high-level

[4] ibid, pp54–59.
[5] ibid, p240.

overview of each element of our proposals. Within this structure we use the annotation of D1, D2, etc to refer to different aspects of price control design that we cover.

Section D1: Cost risk-sharing mechanism

5.45 We propose a mechanism to adjust NIE's maximum revenue and RAB according to differences between the expenditure forecasts we have used for our determination and the level of NIE's out-turn expenditure. We propose that 50 per cent of such differences are passed through to consumers via adjustments to NIE's maximum revenue and RAB.

5.46 The purpose of the mechanism is to provide some financial protection to consumers and NIE against potential inaccuracies in our estimates of NIE's efficient expenditure requirements—whilst also maintaining clear and strong financial incentives for NIE to operate and invest efficiently.

Section D2: Inefficient spend clause

5.47 We propose that NIE's Licence includes a provision that the UR can adjust NIE's maximum regulated revenue or RAB to protect consumers from exposure to costs incurred by NIE which the UR finds to be demonstrably inefficient or wasteful.

Section D3: Measures to tackle risks from deferral of planned network investment

5.48 Under a system of RAB-based incentive regulation, NIE may have financial incentives to defer planned network investment projects with adverse financial consequences for consumers.

5.49 We have considered a number of different options to mitigate this risk. Our proposal involves a policy that, at future price control reviews, there should be no double-funding of any deferred network investment. This will involve an assessment of the extent to which NIE’s investment forecasts for the subsequent price control include expenditure that is needed because of deferral of projects and investment volumes identified in the forecasts used for our determination. We propose annual reporting of investment volumes.

Section D4: Investment projects for distribution network load-related expenditure

5.50 We considered whether to include a mechanism within the price control framework to adjust NIE’s maximum revenue and RAB to include provision for investment to increase the capacity of NIE’s distribution network. This would avoid the need to make an upfront allowance to cover all such investment in the period to 30 September 2017. We considered several different options. We decided that the disadvantages and limitations of these options were large compared with the benefits of such a mechanism. We propose instead to set an upfront allowance.

Section D5: Investment projects to increase transmission system capacity

5.51 We propose provisions within the price control framework 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. The scale of such investment about which there is uncertainty is large and we consider such a mechanism proportionate in this case.

Section D6: Smart grid initiatives

5.52 We have made separate upfront allowances in our cost assessment for some smart grid initiatives proposed by NIE. We do not propose any provisions within the price control framework for the UR to adjust NIE’s maximum revenue and RAB to allow for additional investment in smart grid initiatives.

Section D7: Electricity meter investment and smart meter programme

5.53 We propose a form of 'volume driver' for NIE's capex on electricity meters. We propose to set an upfront forecast for NIE's meter installation and replacement costs and combine this with an adjustment mechanism to vary NIE's allowed revenues and RAB according to differences between *(a)* the actual volume of meter replacement and installation that NIE carries out in each year of the price control period and *(b)* the forecast volumes that were used for the calculation of the upfront cost forecast. NIE would be remunerated on a cost per unit basis for each unit of meter replacement or installation.

Section D8: Pass-through of part of connections charges to NIE's RAB

5.54 NIE imposes charges for new connections to its network (also known as customer contributions). These are subject to price regulation outside the NIE revenue control that is the main subject of our inquiry. At present there is an arrangement by which an element of certain connection charges is 'subsidized' through NIE's RAB and revenue control, rather than falling entirely on the party seeking the new connection. We propose that costs relating to this subsidy from NIE's RAB should be recovered on a cost pass-through basis. This will be a temporary arrangement until 1 October 2014.

Section D9: Pass-through of specified operating costs

5.55 We propose that the regulatory Licence fees that NIE faces are remunerated on a cost pass-through basis.

5.56 We do not propose the pass-through of NIE's rates liabilities or wayleave costs. Instead we make upfront forecasts that cover these costs and NIE will be financially exposed to these costs through the proposed cost risk-sharing mechanism.

5.57 We propose a provision with NIE's Licence for the UR to determine an allowance for costs relating to injurious affection, informed by the outcome of a forthcoming Lands Tribunal determination.

Section D10: Other terms to remove from current Licence conditions

5.58 In addition to the changes to NIE's Licence conditions to implement any proposals adopted above, we propose the removal of several elements of NIE's current price control Licence conditions that are no longer necessary or consistent with other elements of our proposals.

The organization and structure of our work on price control design

5.59 The presentational structure we have adopted departs in some ways from that adopted by the UR (eg the UR's proposals are organized by reference to a number of different expenditure 'funds'). The structure we have used has several benefits:

(a) Much of the dispute in relation to price control design in the inquiry has focused on the 'three-fund' approach to capex that the UR's submissions highlight. But there are other questions of price control design that we need to address and it is helpful to draw these out clearly.

(b) The perception that the UR's proposed approach to capex involves three funds is an oversimplification. The UR's proposals involve different regulatory arrangements for each of six different categories of NIE's capex. The structure we have adopted in this section allows these differences to be presented clearly.

(c) Some questions of price control design, such as questions on an inefficient spend clause and what we have called 'cost risk-sharing mechanisms', apply at a general level and the structure we have adopted helps bring a more consistent approach across different categories of expenditure (where desirable).

5.60 Whilst we present questions of price control design under separate headings, it will be important that the decisions on each aspect are consistent and reflect a coherent strategy for price control and for the inquiry. In developing our provisional determinations, we have sought to achieve a coherent approach.

The role of a reporter and links to price control design

5.61 There are interactions between the UR's proposals for a reporter and our work on price control design. It is useful to draw the following distinction between two types of roles that a 'reporter' might play:

(a) ensuring the accuracy and reliability of data and other information provided by NIE in response to regulatory information requests; and

(b) making assessments of the asset management decisions and plans of NIE to support decisions that the UR will take on (i) whether to approve specific investment proposals identified by NIE and (ii) whether any of NIE's incurred expenditure was inefficient or wasteful and requires a financial adjustment to NIE's allowed revenues or RAB to protect consumers against inefficient costs.

5.62 In each case there is the potential for a reporter to have staff based at the premises of NIE with access to the information necessary to fulfil the reporter's functions: we call this an embedded reporter. The UR proposed an embedded reporter fulfilling roles falling under both categories *(a)* and *(b)* above.

5.63 We consider the role under category *(a)* above in Section 17.

5.64 In this section, we recognize that some potential options for price control design could involve a reporter fulfilling the type of role under category *(b)* and these are identified where relevant. In each case, the reporter would be an optional component which could help make the proposed regulatory arrangements more effective as it would allow the UR to draw on the knowledge of the reporter and its access to information. Such a reporter could also bring downsides, such as risks of regulatory micro-management and blurred responsibilities.

Implementation of price control through licence modifications

5.65 We consider it desirable that, as far as possible, NIE's Licence conditions specify all intended rules that affect the calculation of NIE's maximum regulation revenue or RAB (eg financial adjustments in light of NIE's out-turn costs or volumes of work).

5.66 We found that the UR's proposals for its RP5 price control were not sufficiently well specified to know what financial adjustments would be made to NIE's future regulated revenues and RAB in light of its out-turn costs and the particular network investments it carries out over the price control period. We asked the UR for further clarification of the financial rules it envisaged. Whilst the UR gave us helpful responses, NIE said that our need to seek clarification from the UR indicated deficiencies in the UR's proposals for the RP5 price control.

5.67 It can be difficult and time consuming to transpose intended regulatory arrangements into formal Licence conditions, but doing so can avoid the risks of ambiguity and disputes at a later date. We intend that the more mechanistic elements of price control design discussed below, such as cost risk-sharing arrangements, can be implemented through Licence modifications.

5.68 We shared some of our preliminary analysis with the main parties during the course of our inquiry. NIE raised a concern that our desire for NIE's Licence conditions to specify the rules that affect the calculation of NIE's maximum regulation revenue or RAB may drive us to favour unduly mechanistic approaches to price control design. We do not believe that our proposals suffer from this. We would not favour one approach to price control design over another because it is more conducive to formal specification in price control licence conditions. We have taken into account the risks of ambiguity and future disputes when comparing options, but we do not believe that we have given undue weight to options that can be relatively well specified in licence conditions.

D1: Cost risk-sharing mechanism

5.69 We considered potential arrangements within the price control framework to make adjustments to NIE's revenues and RAB so as to pass through to charges, to some degree, differences between the regulatory forecasts of NIE's expenditure and NIE's out-turn expenditure.

5.70 We use the terminology here of a cost risk-sharing mechanism. Such a mechanism concerns the regulatory treatment of underspends and overspends against regulatory forecasts, the pass-through of actual expenditure (eg to the RAB) and NIE's efficiency incentives. Elements of the UR's proposals for the treatment of capex (eg proposed 'efficiency payments') and its proposals for opex incentives relate to proposals for a cost risk-sharing mechanism.

5.71 A cost risk-sharing mechanism can help reduce consumers' financial exposure to the risks of:

(a) deferral or abandonment by NIE of investment projects that are included in the expenditure forecasts used by the UR to calculate the price control; and

(b) those regulatory expenditure forecasts being too high for any other reason.

5.72 Likewise such a mechanism can reduce the financial exposure of NIE to the risk that the expenditure forecasts used by the UR are too low.

5.73 Cost risk-sharing and pass-through arrangements also have drawbacks. They add complexity to the of the price control framework. There may be a risk—if the degree of pass-through is too much—of undermining incentives for NIE to operate efficiently and to avoid inefficient expenditure. Indeed, there may be a risk of providing NIE with perverse financial incentives to incur expenditure unnecessarily (ie to grow its RAB). There may also be a risk of distorting NIE's working practices, cost reporting and capitalization policies if the nature and extent of cost pass-through is different in different categories of expenditure.

5.74 We need to decide whether to include a cost risk-sharing mechanism within the price control. If we decide to do so, we also need to determine:

(a) whether the cost risk-sharing mechanism should differ between different categories of expenditure;

(b) the extent of cost risk-sharing that is appropriate; and

(c) how the cost risk-sharing mechanism should be implemented.

5.75 We address these points in the following subsections. Before doing so, we briefly summarize submissions from the UR and NIE that relate to cost risk-sharing and discuss some potential shortcomings of the UR's proposals which have led us to explore alternatives.

Summary of the UR's proposals

5.76 The UR's proposals for cost-risk sharing in relation to capex are embedded within its proposals for the different capex funds that it identifies. These proposals are described in Appendix 5.1. The UR's proposals for cost risk-sharing include the following:

(a) Cost risk-sharing for capex would be implemented by adjusting NIE's RAB in light of its actual expenditure with a five-year delay. NIE's price control would initially

be calculated to provide it with depreciation and allowed return on the value of its RAB which is based on regulatory forecasts of NIE's capex. NIE's RAB would be subsequently recalculated in light of its actual capex so as to provide NIE with the depreciation and allowed return due on its actual capex (rather than the regulatory forecast)—but with that recalculation only taking effect on NIE's maximum regulated revenue after a five-year delay.

(b) For some parts of NIE's capex there would be no cost risk-sharing. NIE and consumers would be fully exposed to the expenditure forecasts made by the UR at the price control review with no adjustments for any differences between forecast expenditure and actual expenditure.

(c) For opex, the UR proposed a variant of the 'operating expenditure incentive allowance' that Ofwat introduced at the 1999 periodic review. Under this approach, financial adjustments would be made to try to ensure that NIE would benefit from any savings in its opex (against regulatory forecasts) for a period of five years.

Summary of NIE's proposals

5.77 For those categories of capex identified by NIE as suitable for an ex-ante allowance, NIE's proposals are for NIE to bear a set proportion of underspend or overspend relative to that ex-ante allowance.[6] NIE proposed that the CC set a symmetrical efficiency incentive scheme for opex.[7]

5.78 In a more recent submission, NIE said that cost risk-sharing arrangements could either be applied as a 'fixed percentage to be determined' or as a scheme under which NIE would 'retain outperformance/underperformance (depreciation plus return) for five years'.

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[6] ibid, p55.
[7] ibid, p240.

5.79 NIE told us that it saw merit in an alignment of cost risk-sharing across opex and capex.

UR's proposals for different cost risk-sharing between expenditure categories

5.80 The UR's proposals would involve substantially different policies on cost risk-sharing between different expenditure categories. Differences would apply between different categories of capex and between opex and capex.

5.81 The UR's proposals for output measurable capex in Fund 1 and for load-related expenditure in Fund 2 would involve a pass-through of differences between NIE's out-turn and forecast unit costs to the RAB after five years. This would mean that revenues would be adjusted to provide NIE with compensation for a substantial proportion of any overspend it incurs in relation to capex unit costs.

5.82 In contrast, there would be no similar mechanism in relation to overspend in relation to controllable opex. In effect, NIE would bear the full financial impact of its opex being above the regulatory forecasts but would be compensated if its asset replacement expenditure is above regulatory forecasts.

5.83 At the next price control review, there would be no guarantee that increases in NIE's opex would feed through to higher revenues in the subsequent price control period. The determination of a future allowance for NIE's opex may be partially or heavily influenced by the costs of other electricity companies as part of a benchmarking exercise, rather than simply being set using an extrapolation of NIE's own historical costs. An approach to cost assessment that gives weight to the results from benchmarking exercises, rather than NIE's historical costs, will limit NIE's ability to recover additional revenue at future price controls as a result of any cost increases it has experienced. The UR told us that it considered a benchmarking exercise necessary as part of price control reviews to meet the requirement of assessing whether NIE's costs are efficient.

5.84 There are also differences between different categories of capex. The UR's proposals for input-driven items within Fund 1 would involve no adjustment or pass-though for any differences between the costs NIE incurs for activities within this category. There would be no cost risk-sharing for this category of expenditure which implies a different regulatory treatment compared with output-measurable capex.

5.85 These differences may provide NIE with financial incentives to distort its working practices and accounting practices to favour specific categories of expenditure. There may be an opportunity for NIE to earn additional profits, at consumers' expense, simply from changes to working practices or accounting practices in a way that reallocates expenditure between categories. These risks seem particularly relevant to our inquiry given the concerns that the UR has raised about changes in NIE's capitalization practices in the past.

UR's proposed opex outperformance rolling incentive

5.86 The UR's proposals are to introduce a new incentive scheme for opex which is a variant on the opex incentive allowance introduced by Ofwat at the 1999 periodic review.[8] The UR explained the aim of its proposals in relation to opex as follows:

> The rolling opex incentive proposed by the Utility Regulator for RP5 will allow NIE to keep controllable operating cost savings for (a fixed period of) five years, regardless of when in the control period the saving is made. We will however, where NIE over-spends on opex, confine any penalties to within the price control period. We believe this is a sufficient incentive to discourage the company from over-spending. This will be

[8] Ofwat: *Final determinations: future water and sewerage charges 2000–05,* 1999, p91.

reinforced by ensuring that any such over-spends are not automatically reflected in the allowed revenue in the subsequent price control (RP6) – with the case for any such increases closely scrutinised.

Our aim is to create an opex outperformance rolling incentive to ensure that NIE is not incentivised to maximise the period of time the savings are retained by making savings early in the regulatory period (with later savings perhaps deferred until the early years of the subsequent price control period to maximise potential outperformance revenue for the company).

5.87 The use of Ofwat's operating expenditure incentive allowance may provide a way to mitigate the UR's concern that NIE might make opex savings early in the regulatory period and might be discouraged from making savings later in the period. However, there are other ways to address that concern. Most importantly, the use of cost benchmarking analysis as part of cost assessment work can reduce the reliance placed on NIE's own historical costs in setting its price control, which limits this concern.

5.88 Further, Ofwat's operating expenditure incentive allowance should be seen in the context of the other elements of the regulatory framework in which it was applied. Ofwat's historical approach to the treatment of over- and underspends in relation to opex and capex is likely to have contributed to financial incentives for regulated water companies to favour capex over opex.

5.89 Ofwat has reviewed its own price control framework over the last few years and has proposed extensive changes. It published a methodology paper in July.[9] Ofwat said that it did not intend to retain the operating expenditure incentive allowance. Instead,

[9] Ofwat 'Setting price controls for 2015–20: final methodology and expectations for companies' business plans', July 2013.

Ofwat proposed a total expenditure or 'totex' approach. Under this approach, overspend and underspend in relation to operating would be treated the same way as for capex, with an 'efficiency sharing factor' determining the extent to which overspend and underspend against regulatory baseline levels of expenditure is passed through to consumers. Ofwat's proposals share similarities with the total expenditure approach developed by Ofgem. Ofwat was concerned that its previous approach to price control regulation introduced a bias in favour of capex.

Proposed alignment of cost risk-sharing across opex and capex

5.90 We see merit in better aligning the approach to cost risk-sharing—and hence efficiency incentives—across opex and capex. This regulatory approach has been applied by Ofgem to energy network price control reviews over the last few years and has also been proposed by Ofwat for its current review of water and sewerage price limits.

5.91 We propose a form of cost risk-sharing in which we specify a fixed percentage of the difference between the regulatory forecasts of NIE's expenditure and NIE's actual expenditure which is to be passed through to charges to consumers via adjustments to NIE's maximum revenues and RAB. The greater this proportion, the greater is the extent to which actual expenditure is passed through to consumers. NIE's submissions identified this type of approach as a feasible option.

5.92 The approach of specifying a fixed percentage is more amenable to alignment of cost risk-sharing across capex and opex than an approach of making adjustments for outturn expenditure after a delay of five years.

5.93 Ofgem's approach to the regulation of energy networks in GB uses a fixed percentage. It refers to the 'efficiency incentive rate', with a higher rate meaning less cost pass-through and greater financial exposure and efficiency incentives for the regulated companies. This efficiency incentive rate is effectively 1 minus the pass-through percentage we envisage above.

5.94 One feature of the approach adopted by Ofgem (and supported by Ofwat) is that overspends and underspends in relation to opex would feed through and affect the level of the regulated company's RAB. Historically, the RAB for regulated companies such as NIE has been adjusted over time according to forecast capex and out-turn capex. The application of Ofgem's approach to NIE would represent a significant change in what the RAB represents.

5.95 In this light, we identified two options:

(a) implement cost risk-sharing in the same way for opex and capex, accepting that NIE's actual level of opex will affect the size of its RAB; and

(b) maintain a policy that the RAB is only adjusted for forecast or actual capex. Under this approach the cost risk-sharing mechanism would be implemented through separate financial adjustments for capex and opex. Differences between forecast and out-turn capex would lead to an adjustment to NIE's RAB (and consequent adjustments to maximum regulated revenues). Differences between forecast and out-turn opex would lead an adjustment to NIE's maximum regulated revenue but no adjustment to NIE's RAB. The calculation of adjustments for opex and capex would be made with the aim of applying the same extent of cost pass-through in each case.

5.96 The first option would involve a lower risk that NIE faces financial incentives to distort its expenditure decisions (and cost reporting) in favour of capex. But it would involve more substantial changes to the nature of NIE's RAB.

5.97 NIE told us that it was neutral regarding the choice between the two options in paragraph 5.96 above 'as long as the economic effect is the same'. We do not believe that the economic effect of these options on NIE is the same. Whilst it is possible to make calculations to show that the net present value (NPV) of the effects of these two options could be the same, any calculations of this nature can only be approximate. We do not know NIE's precise valuation of the time value of money or its attitude towards any risks relating to the recovery of its RAB.

5.98 The UR raised concerns regarding intergeneration equity among consumers if the mechanism meant that variations in NIE's opex fed through to its RAB. The UR also told us that the first option in paragraph 5.96 above might not be compatible with EU requirements for cost-reflective tariffs if the cost risk-sharing arrangement covered costs relating to the substantial investment required to accommodate renewable generation.[10]

5.99 We propose to adopt the approach under paragraph 5.96*(b)* above in which the cost risk-sharing arrangement operates through separate financial adjustments for opex and capex. We expect that, compared with current Licence conditions, our proposals would make a substantial reduction to the risk that NIE's incentives across opex and capex are not fully aligned—in particular, that NIE may have financial incentives to favour capex even where an opex solution would be more efficient. Whilst some further reductions to that risk might be possible if we followed the approach adopted by Ofgem, we were concerned that these would involve substantial changes in the nature of NIE's RAB which would not be easy to undo. The UR and NIE will have opportunities to give further consideration to a move to an approach to cost risk-sharing more in line with Ofgem's as part of the next price control review for NIE.

[10] We did not investigate the UR's concern about compliance with EU requirements for cost-reflective tariffs as part of our inquiry. We decided that even leaving aside that concern, the approach favoured by the UR was preferable at this stage.

Concerns raised by the UR on proposed approach to cost risk-sharing

5.100 We shared our initial analysis on cost risk-sharing with NIE and the UR. The UR raised some concerns with the approach we have proposed above, particularly in relation to opex. We reviewed the UR's submissions and are satisfied that our proposals are appropriate.

5.101 We provide more information on the concerns raised by the UR and our assessment of them in Appendix 5.2. In short, the UR was concerned that our proposals would: *(a)* weaken the incentives faced by NIE in relation to its opex; *(b)* introduce differences to the strength of financial incentives that NIE faces during the course of the price control period; and *(c)* fail to achieve consistent incentives across opex and capex. We believe that the UR's concerns are overstated. They overlook the opportunities—which we have taken—to use the results of benchmarking analysis to set a price control for NIE that is not heavily dependent on its historical expenditure.

5.102 The cost-risk sharing mechanism and incentive structure that we propose will not necessarily equalize NIE's incentives between opex and capex or ensure that NIE faces financial incentives to take decisions between opex and capex that are compatible with minimization of whole-life costs. We are not aware of any system of RAB-based price control regulation that does not entail any risk of distorting the regulated company's incentives between different categories of expenditure to some degree. Instead, our position is that the approach we propose—when taken in combination with our proposed approach to cost assessment and benchmarking analysis—poses less risk of unduly distorting NIE's decisions between opex and capex approaches than either *(a)* NIE's current price control Licence conditions or *(b)* the alternative approach proposed by the UR.

Choice of percentage for the cost risk-sharing mechanism

The issue

5.103 We need to decide on what percentage to apply under the cost risk-sharing arrangement. We have given weight to regulatory precedent and the following factors:

(a) The greater the extent of pass-through, the more protection there is against cost forecasting and investment deferral risks (see paragraph 5.26).

(b) If the extent of pass-through is too high, NIE may face insufficient financial incentives to reduce costs. There is even a risk that NIE may face financial incentives to incur expenditure unnecessarily (eg to grow its RAB).

Regulatory precedent

5.104 The most relevant regulatory precedent is from Ofgem's regulation of GB energy networks. Under Ofgem's approach, the efficiency incentive rate varies between companies: its exact value depends on Ofgem's decisions on whether to 'fast track' the price control review for the company (if it has a high-quality business plan) and on a regulatory incentive scheme relating to companies' business plans called the Information Quality Incentive scheme (or IQI). Accordingly, this means that Ofgem determines the approximate level of the efficiency incentive rate and hence—in the terminology we use here—the extent of cost risk-sharing.

5.105 The most recent price controls that Ofgem set were for electricity transmission companies, the gas transmission company and the gas distribution companies from April 2013:

(a) For National Grid electricity transmission the efficiency incentive rate was set to 47 per cent and for National Grid gas transmission the rate was 44 per cent.[11]

[11] Ofgem 'RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas', December 2012, p31 & p46.

(b) For the two Scottish electricity transmission companies, the efficiency incentive rate was 50 per cent.[12]

(c) For the gas distribution network companies, the efficiency incentive rates varied between 62 and 64 per cent.[13]

5.106 In its strategy decision for the next electricity distribution price control review, Ofgem proposes an approach in which the efficiency incentive rate would vary between companies within a range between 50 and 70 per cent.[14] This implies that the extent to which differences between forecast and actual expenditure is passed through to consumers would vary between companies in a range between 30 and 50 per cent. In the same document, Ofgem reports that the corresponding efficiency incentive rate in the current price control period, which started in 2010, was in a range of 53 to 59 per cent.

Parties' views

5.107 The UR submitted the following on the choice of incentive rate:

> We note that Ofgem and Ofwat have awarded high incentive rates to companies with good quality business plans and low incentive rates to companies where there has been less confidence in submitted plans. NIE T&D's RP5 plan is very clearly of the latter type and, as such, we would not expect the Commission to want to increase the financial rewards that NIE T&D can earn in RP5 for beating its plan relative to the rewards that we proposed in our FD.

[12] Ofgem 'RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd', April 2012, p18 & p24.
[13] Ofgem 'RIIO-GD1: Final Proposals – Overview', December 2012, p29.
[14] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control: overview', March 2013, p34.

5.108 The UR told us that the implied efficiency incentive rate in its proposal was 30 per cent. This would represent an intention to pass through around 70 per cent of variations between forecast and actual costs to consumers.

5.109 NIE submitted that an efficiency incentive rate of 30 per cent was appropriate for opex and capex, which it said was consistent with its previous proposals for capex.

5.110 NIE submitted that the efficiency incentive rates indicated by the regulatory precedent referred to above did not form a useful starting point for NIE for the purposes of our inquiry. NIE argued that because aspects of our approach to price control design differed from Ofgem's price control framework, we should not set a similar percentage to that implied by the efficiency incentive rate in Ofgem's recent decisions and proposals. NIE argued that our proposed arrangements to tackle concerns about the impact of investment deferral on consumers (section D3 below) are highly prescriptive and do not offer NIE the same degree of commercial freedom as for companies regulated by Ofgem.

Our provisional view

5.111 We have considered these submissions carefully and propose a cost-risk sharing percentage of 50 per cent. This figure also represents what Ofgem would define as an efficiency incentive rate of 50 per cent. The choice of percentage is a matter of regulatory judgement. We have given particular weight to Ofgem precedent and an objective of ensuring that NIE's financial exposure to its costs is high for it to avoid unnecessary expenditure and to have clear profit opportunities to improve the efficiency of its operations and investment.

5.112 Our proposed percentage involves substantially less cost pass-through than proposed by the parties. We do not accept NIE's argument that the differences in our proposals and Ofgem's price control framework for electricity distribution companies imply that we should not take guidance from the efficiency incentive rate set by Ofgem and that we should instead choose a percentage that gives rise to a larger degree of protection to NIE against financial risk. We consider the Ofgem precedent relevant for our purposes because of a feature common to Ofgem's approach and our own: the objective of ensuring that regulated companies have sufficient financial incentives to reduce and restrain their costs. In line with Ofgem's approach, we do not consider the percentages proposed by NIE or the UR to be sufficient for these purposes.

Implementation of cost risk-sharing mechanism

5.113 We have considered how our proposals for cost risk-sharing should be implemented.

5.114 Ofgem developed a mechanism to make annual adjustments to revenues for cost risk-sharing purposes. Ofgem's approach involves rerunning a complicated Excel-based financial model every year. We considered whether simpler approaches may be possible for the purposes of our determination.

5.115 We propose a scheme that has the following features:

(a) The cost-risk sharing percentage is specified as 50 per cent, as proposed above (paragraph 5.112).

(b) The cost risk-sharing mechanism would apply to all NIE's costs across opex and capex which are not specifically excluded. Excluded items would comprise: (i) the costs of items identified for full cost pass-through; (ii) any profit margin charged to NIE by NIE Powerteam (or other similar related business) and (iii) costs recharged by NIE to associated businesses.

(c) A single-year adjustment to NIE's maximum regulated revenue would be made in relation to the difference between the regulatory forecast of opex for the financial year two years previously and NIE's actual opex two years previously.

(d) For capex, an adjustment would be made to NIE's RAB in relation to the difference between the regulatory forecast of capex for the financial year two years previously and NIE's actual capex two years previously.

(e) For both opex and capex the value of the adjustment would be calculated as the relevant difference in expenditure, multiplied by the value of the cost risk-sharing percentage (50 per cent) and then adjusted using a discount rate over a two-year period to account for the NIE's time value of money between the cost variation and the implementation of the adjustment. For the purposes of that discount rate we would use the interest rate from the correction factor (KD_t term) in NIE's current Licence conditions.

(f) The calculation method for the adjustments would be specified in NIE's Licence conditions.

5.116 These mechanisms would rely on annual reporting of cost data and calculation of the price control according to specified formulae and the latest data. The data requirements and calculation processes seem no more demanding than the RP4 price control for NIE, which involved annual recalculation of the price control and RAB during the price control period in light of historical data on capex and controllable opex.

D2: Inefficient spend clause

5.117 The UR proposed an 'efficient spend clause' as part of its proposals for the different elements of NIE's capex. This would allow the UR to adjust NIE's regulated revenue and RAB to prevent consumers from being exposed to costs that the UR considered inefficient—perhaps in light of analysis from the UR's proposed reporter. NIE raised concerns about the ex-post nature of the UR's proposals and the regulatory risk it would face.

Clarification of UR's proposals

5.118 In its draft and final determinations, the UR's proposals for an efficient spend clause were not tightly specified and presented a risk—identified by NIE—that the UR could deem amounts of NIE's past capex inefficient and prevent NIE from recovering that expenditure through future revenues.

5.119 At the start of our inquiry the parties seemed a long way apart in their views on the inefficient spend clause. We established that the proposals presented by the UR could be interpreted more widely than the UR had envisaged: it sought a provision to make clear that it could disallow expenditure that was demonstrably wasteful. The UR was not seeking to penalize NIE for failing to achieve some hypothetical ideal or to make NIE price control determination conditional on NIE's proof of its own efficiency.

Ofgem policy on demonstrably inefficient or wasteful expenditure

5.120 Ofgem includes provisions within its price control framework to make clear that it can make financial adjustments that have the effect of 'disallowing' the company from recovery of demonstrably inefficient or wasteful costs from charges to consumers.

5.121 For example, in its final proposals for a new price control for National Grid's electricity and gas transmission businesses, published in December 2012, Ofgem included the following in the Finance Supporting document:[15]

> Ofgem reserves the option to disallow costs from the RAV if they do not relate to the regulated business or are demonstrably inefficient or

[15] Ofgem Final Proposals for NGET and NGG, p76.

wasteful. We will specifically review all costs in relation to restructuring of a company's business or operations in relation to corporate transactions, including the associated redundancy costs to satisfy ourselves that these costs are efficient and will deliver future savings for the benefit of the consumer.

5.122 Similarly, in its strategy decision for a new price control for electricity distribution companies, Ofgem said that it 'reserves the option to disallow costs from totex and, hence RAV, if they do not relate to the regulated business or are demonstrably inefficient or wasteful'.[16]

Our assessment

5.123 The Ofgem terminology of 'demonstrably inefficient or wasteful' expenditure seems fit for purpose and consistent with the UR's intentions as clarified at the hearing in July 2013. We propose to include a provision within NIE's Licence conditions that the UR can make adjustments to NIE's revenues or RAB to protect consumers from exposure to any costs that are demonstrably inefficient or wasteful.

5.124 This clause will apply across all areas of NIE's expenditure. Although the UR's original proposals were in relation to capex, there seems no good reason to limit its application to capex; it should apply to all categories of NIE's expenditure. The clause should apply regardless of whether NIE underspends or overspends in relation to regulatory forecasts.

5.125 Whilst NIE might face some 'ex-post' financial risk under an inefficient spend clause of this nature, we do not consider NIE's exposure to such risk to be unreasonable in light of the statutory duties on NIE and also the UR.

[16] Ofgem 'Strategy decision for the RIIO-ED1 electricity distribution price control', March 2013, p63.

5.126 By way of further clarification, we highlight two things that we would not expect to fall within the scope of such a clause:

(a) If something only turned out to be inefficient or wasteful with the benefit of hindsight, rather than with information reasonably available at the time, we would not expect it to be considered to be demonstrably inefficient or wasteful.

(b) The type of high-level econometric models used for benchmarking purposes in this inquiry, and by regulators such as Ofgem and Ofwat, can help produce estimates of a regulated company's expenditure requirements over a future period. The use of such models has desirable properties as part of a regime of incentive regulation because it can reduce the regulator's reliance on the regulated company's own out-turn costs. But such econometric models do not (by themselves) demonstrate inefficient or wasteful expenditure that is relevant to the proposed clause above.

5.127 The UR told us that it supported the proposals above. NIE also told us that it was content with these proposals.

5.128 NIE also asked for us to provide examples of the exceptional circumstances in which the inefficient spend clause might bite. We have not developed such examples. There is a danger in seeking to define the inefficient spend clause through hypothetical examples which inevitably abstract from many aspects that would be relevant to a factual investigation under this provision. We do not want to focus the scope of the inefficient spend clause on any particular examples that we might provide.

5.129 NIE also suggested that the principles above relating to the benefit of hindsight and the role of econometric models were very important and should be reflected in licence modifications. We agree with these proposals.

5.130 In addition, NIE proposed that Licence modifications should include the following elements to reinforce our proposals above:

(a) a requirement that it should be for the UR to demonstrate that any particular item of expenditure was demonstrably inefficient or wasteful;

(b) a requirement that the UR raise with NIE any matters which it considered might lead to a determination that expenditure was inefficient or wasteful at the earliest opportunity that would enable NIE to take appropriate steps to prevent any further expenditure that might fall within the scope of the determination; and

(c) a requirement that, in any event, any determination that expenditure is inefficient or wasteful should be made no later than the conclusion of the UR's price control review for the period following that in which the expenditure was incurred or, in the case of expenditure that was not reported to the UR in the course of the price control review (eg because it post-dated the submission of NIE's business plan submission), within two years of the expenditure being incurred. (NIE said that it would expose NIE to unwarranted regulatory risk if the UR was able to reopen expenditure decisions many years after the expenditure had been incurred, and when it was likely to be difficult for NIE to obtain evidence of the context and circumstances in which a particular expenditure decision had been taken.)

5.131 We agree with the proposal under paragraph 5.131*(a)*: we think this follows naturally from the way that we have specified the clause above. We would expect the UR to publish a reasoned decision for any adjustment to NIE's maximum regulated revenue of RAB in light an assessment under the proposed inefficient spend clause.

5.132 Whilst we accept that the behaviour sought from the UR under paragraph 5.131*(b)* and *(c)* above would contribute to good administrative practice, we do not consider it necessary or appropriate to put such restrictions in place as part of modifications to NIE's price control Licence conditions. We expect that it would be in the UR's interests to address any concerns sooner rather than later because delays will tend to make it more difficult to collect the information necessary to justify any finding of demonstrably inefficient or wasteful expenditure. But we do not consider it appropriate for us to give NIE an amnesty from the clause if the UR has missed some interpretation of the 'earliest opportunity' or after a particular length of time.

D3: Measures to tackle risks from deferral of planned network investment

5.133 We have given careful consideration to a risk that may arise under some forms of RAB-based price controls which concerns the potential opportunity for NIE to defer forecast investment projects to the detriment of consumers (see paragraph 5.26). In its RP5 final determinations and its submissions to us, the UR emphasized the importance of tackling this risk. At the same time, we have also recognized that some investment deferral may be efficient.

5.134 This section is structured as follows. We *(a)* provide more information on the opportunity to defer planned projects to the detriment of consumers that we are concerned with. We *(b)* provide an overview of the different options we have considered to tackle this risk and summarize our assessment of these options. We *(c)* describe our proposed approach in some detail and discuss the submissions that we have received from the UR and NIE on this proposal. We provide further information and analysis on the options we have considered in Appendix 5.3.

Opportunity to defer planned projects to detriment of consumers

5.135 Unless a price control involves full pass-through of any underspend against the regulator's upfront cost assessment, the regulated company may have a profit opportunity, or financial incentive, to spend less than envisaged at the price control review. Such profit opportunities can help encourage the company to operate efficiently. However, there is a risk that the company can profit from deferring or cancelling planned network investment projects, or reducing the volume of work it does on the network, to the detriment of consumers.

5.136 The following categorization is intended to illustrate in a simplified way one of the sources of this risk. We identify two (of several) possible purposes for expenditure that a regulated network company carries out during a five-year price control period:

(a) Some expenditure projects and volumes of work will be absolutely necessary within the five-year price control period to maintain services to electricity consumers, to deliver any specified 'outputs' or 'deliverables' required of the company under the price control, to comply with network design and planning standards, and/or to meet other legal obligations.

(b) There may be other expenditure projects and volumes of work which do not fall under *(a)* but which are nonetheless efficient or reasonable to carry out during the five-year price control period (eg in light of an appraisal of options on a whole-life cost basis). Such work may represent best practice asset management but its purpose is partly an economic one—achieving lower costs over the longer term—rather than one of simply maintaining services to current consumers and compliance with obligations. To take one example, a programme of planned asset refurbishment and replacement of overhead lines may be lower cost, over the long term, than case-by-case reactive replacement of specific assets which fail or considered to be close to failure.

5.137 If the upfront cost assessment used in the calculation of the price control includes expenditure for the type of work under category *(b)* above, consumers may face charges that are intended to cover expenditure that the regulated company does not strictly need to carry out within that price control period. Whilst it may be efficient for the company to carry out the work under *(b)*, if there is nothing to compel the company to do so, it may refrain from carrying out that work (eg by delaying, scaling down or cancelling planned investment projects).

5.138 The scope for such deferral is linked to the fixed-term nature of the price control and the opportunity, at the next price control review, for the regulated company to make a fresh bid for the expenditure it needs over the following next price control period in light of the age and condition of its network assets. The potential harm to consumers arises not so much from the deferral itself but from the possibility that, as a result of the deferral, the company requires greater expenditure in the future, which may lead to higher charges to consumers.

5.139 A further source of the risk relating to investment deferral arises from the possibility for different interpretations of the obligations that apply in relation to expenditure category *(a)* above. For instance, the regulated company might take one view of its safety obligations and determine that a particular substation on its network is unsafe and requires replacement before the end of the price control period. But another interpretation of its safety obligations may be possible in which the substation replacement can be deferred to the next price control period.

5.140 Finally, in considering the opportunity to defer planned projects to the detriment of consumers, we should also recognize that there may be offsetting financial incentives and other factors that influence a company’s behaviour. If the regulated company has included substantial work that would fall under category *(b)* above in its business plan submissions to the regulator at the price control review, and if the regulator’s upfront cost assessment reflected those submissions, the company may be concerned that it will suffer reputational damage if it makes a large profit from deferring or cancelling those projects—which comes back to haunt it in some way at subsequent price control reviews. The regulated company may also build up a backlog of work needed on the network which there is no guarantee that it will be able to finance in the future. Further, depending on the details of the price control framework and the strategy of the company, the company may carry out some work that falls under category *(b)* because it faces financial incentives to invest as much as is reasonably possible in order to grow or maintain the value of its RAB.

Overview of options identified to tackle investment deferral risk

5.141 We have considered a range of measures or options to help tackle this risk set out above. In brief terms, these are as follows (see Appendix 5.3 for more information):

(a) *Volume adjustment mechanism with volume cap.* This is our interpretation of the feature of the UR's proposals that can address the risk of investment deferral to the detriment of consumers. The UR proposed a form of volume adjustment mechanism under which the maximum revenue and RAB that NIE is entitled to under the price control would be linked, mechanistically, to the volume of work it carries out under a series of specified network investment project categories (eg 11 kV overhead line re-engineering). Such a mechanism would have the effect of exposing NIE financially to the unit costs of network investment, but not to the volume of investment that it carries out (subject to some aggregate cap). It would allow NIE to substitute between different categories of network investment project according to the ratio between the unit cost allowances set by the regulator for different categories of investment.

(b) *Ofgem outputs and secondary deliverables.* Ofgem's price control framework for energy network companies includes the specification of a series of outputs and 'secondary deliverables' that companies are held to as part of the price control agreement, with financial consequences for underdelivery. The secondary deliverables include requirements in terms of maintaining the health and condition of assets across a company's network. Ofgem's approach rests on detailed reporting of data relating to individual network assets.

(c) *NIE's proposed cap and collar mechanism.* NIE proposed that concerns about investment deferral could be tackled by an arrangement under which its financial exposure to the upfront regulatory expenditure allowance would only apply between a lower limit (the 'collar') and an upper limit (the cap). Any expenditure that NIE incurs that is outside the range of the cap and collar would be subject to full pass-through to consumers. If NIE were to spend substantially less than the lower limit (collar)—perhaps through deferral of forecast investment projects—the savings in expenditure below the cap would feed through to lower charges to consumers and NIE would not profit from those savings. This feature of the proposal would reduce the extent to which NIE would profit from deferral or abandonment of forecast investment projects and it would reduce consumers' financial exposure to the risks of such deferral or abandonment. Conversely, if NIE were to spend more than the cap, charges to consumers would subsequently rise to fully compensate NIE for the costs it has incurred in excess of the cap.

(d) *Pass-through of network investment costs subject to a cap.* Under this approach, we would take our forecast of NIE's expenditure requirements over the price control period and use this to set a cap on its investment over the period. If NIE's actual expenditure on network investment exceeds the cap, the normal cost risk-sharing mechanism would apply (see section D1 above). If NIE spends less than the cap, that cost risk-sharing mechanism would not apply: instead adjustments to NIE's maximum revenues and RAB would be made to deny NIE financial benefits from spending less than the cap and to avoid consumers paying for planned investment that NIE does not carry out.

(e) *Capex allowance reflecting investment deferral risk.* Under this approach, we would seek to limit the risks to consumers from investment deferral by setting the price control on the basis of a relatively low forecast of NIE's capex, which reflects an expectation that, in response to the financial incentives of the price control, it is likely to defer some of the investment projects that were included in its business plan. Such an approach would probably exclude some expenditure that could be justified as efficient on a whole-life cost basis but which could be deferred without serious adverse consequences to NIE.

(f) *Compliance with asset management documentation.* We identified a potential option under which we would require NIE to comply with asset management documentation that specifies how it would make decisions in relation to asset replacement and refurbishment. NIE's opportunities for investment deferral would be constrained to the extent that deferral or abandonment of planned investment may not be compatible with the asset management documentation. The documentation would need to refer to observable and verifiable information and it would need to be consistent with the network investment forecasts used to calculate the price control.

(g) *No double-funding of deferred network investment.* The starting point for this approach is a recognition that the risk of NIE deferring network investment to the detriment of consumers stems in part from the opportunity for NIE to seek (and be allowed) additional revenue in subsequent price control periods to cover any costs it expects to incur to make up for the consequences of its investment deferral in the past. The aim of the approach is not to prevent investment deferral—some of which may be efficient—but rather to protect consumers from adverse financial consequences in the event of investment deferral. This option is based on a policy that, at future price control reviews, the determination of NIE's maximum revenue and RAB should be done by reference to a policy that there should be no double-funding of deferred network investment. This would be achieved in practice through a clear specification of volumes of investment included in forecasts used to set the price control, regular reporting of volumes during the price control period and potential deductions for 'pre-funded costs' as part of the assessment of NIE's expenditure forecasts at the subsequent price control review.

5.142 The breadth of options reflects: *(a)* the importance we have given to the concerns raised by the UR; *(b)* NIE's strong criticisms of the UR's proposals; and *(c)* the lack of an established and proven regulatory solution that is feasible for our inquiry.

5.143 In addition, we also considered a 'do nothing' option. Whilst this approach would not eliminate concerns about investment deferral risk, it is worth comparing against other options which may carry adverse side effects. Under this approach the extent of harm from any deferral would be mitigated, to some degree, by the pass-through of actual costs to consumers under any cost risk-sharing mechanism. NIE's original submissions to us were for a 'do nothing' option in relation to investment deferral risk.

5.144 Appendix 5.3 provides more information on the options, the main parties' submissions on these options and our assessment of them. We summarize our assessment below.

Our assessment

5.145 Our proposed approach is option *(g)* above: no double-funding of deferred network investment.

5.146 We found that options *(b)* (Ofgem outputs and secondary deliverables) and *(f)* (compliance with asset management documentation) were not feasible in the timescale of our inquiry. The UR and NIE have both been supportive of Ofgem's approach but it rests on detailed information about the condition of NIE's assets across its system. Neither NIE nor the UR considered it feasible to attain the information necessary to implement Ofgem's approach within the time frame of our inquiry. There currently exists no asset management documentation that would fulfil the role envisaged under option *(f)*. We did not consider it possible to develop such documentation during the time frame of our inquiry; NIE told us that this was not practical.

5.147 We do not consider that options *(c)* (NIE's proposed cap and collar mechanism) or *(d)* (pass-through of network investment costs subject to a cap) would provide sufficient financial incentives for NIE to avoid unnecessary expenditure and to improve the efficiency of its operations and investment. Both of these options would involve cost pass-through to consumers. Furthermore, option *(c)* would provide particularly limited protection against the risks relating to investment deferral if the 'collar' in the scheme was not set close to the regulatory forecast of expenditure.

5.148 We saw some merit in option *(e)* (capex allowance reflecting investment deferral risk) but recognized that, whilst reducing risks of investment deferral to the detriment of consumers, it is likely to lead to NIE missing opportunities to make investments that could help reduce costs to consumers over the long term.

5.149 The UR emphasized similarities between its original proposal of option *(a)* (volume-adjustment mechanism with volume cap) and our proposal of option *(g)*. The UR favours option *(a)*. In contrast, we consider option *(g)* to be considerably better. Option *(g)* would provide greater financial incentives for NIE to improve on the network investment plan used as the basis for our price control calculations: NIE would face financial incentives to defer investment where this is efficient and to abandon (or downsize) planned investment projects that are no longer needed. We consider these features of option *(g)* particularly desirable.

5.150 Further, we were concerned about the risk that option *(a)* would provide NIE with perverse incentives to skew its investment plan in favour of those categories of network investment that it is 'well paid' to do under the unit cost allowances underpinning the volume adjustment mechanism—we were also concerned about the potential need for an embedded reporter within NIE to help tackle that concern.

5.151 Finally, we considered whether our preferred option *(g)* is better than a 'do-nothing option'. We are satisfied that it is. As discussed further below, there is some risk that—compared with the do-nothing option—option *(g)* reduces the extent to which NIE would choose to reoptimize its network investment plan over the price control period. But under option *(g)* NIE would still have substantial freedom and incentive to adapt its investment plan over the price control period in light of changing conditions and new information. We consider that any residual limitations on NIE's flexibility would be outweighed by the contribution it would make to the serious concerns that we have about investment deferral to the detriment of consumers.

5.152 We expect that option *(g)* would expose NIE to more financial risk than the do-nothing option. We do not consider this factor sufficient to lead us to prefer the do-nothing option. Under the do-nothing option we would expect NIE to have a much smaller exposure to financial downside in relation to the costs it incurs over the price control period than it has to financial upside in relation to these costs: NIE would have extensive opportunities to offset any unexpected cost increases (eg from unanticipated input price rises or abnormally high levels of faults) by scaling back investment in areas where it has scope for deferral. The financial risk to NIE seems more balanced under option *(g)*: whilst NIE would face some potential financial down-side in relation to unexpected costs, it would also have opportunities for financial upside.

5.153 We describe our proposed approach in detail in paragraphs 5.155 to 5.224 below. As part of the discussion we also consider a variation on it that was submitted by NIE during our inquiry.

Proposed policy of no double-funding of deferred network investment

5.154 The starting point for our proposed approach is a recognition that the risk of NIE deferring network investment to the detriment of consumers stems in part from the opportunity for NIE to seek (and be allowed) additional revenue in subsequent price control periods to cover any costs it expects to incur to make up for the consequences of its investment deferral in the past.

5.155 The aim of the approach is not to prevent investment deferral—some of which may be efficient—but rather to protect consumers from adverse financial consequences in the event of investment deferral. The approach would be based on an expectation that, at future price control reviews, the determination of NIE's maximum revenue and RAB should be done by reference to a policy that there should be no double-funding of deferred network investment. The cost assessment carried out at the next price control review would seek to protect consumers from exposure to costs arising from deferral of investment planned in the period to September 2017.

5.156 On its own, a policy that the new price control from October 2017 will be set to ensure 'no double-funding of deferred network investment' may not be effective. It may be difficult to establish which elements of NIE's investment plan for the period from October 2017 were already included in the calculation of the price control for the period from April 2012 to September 2017.

5.157 It will be important to ensure that, as far as possible, the price control we determine as part of the current inquiry involves a transparent reconciliation between the overall capex forecast used to calculate the price control and forecasts of the costs and volumes of specific network investment projects.

5.158 With this in place we envisage that, as part of the planned price control review for the price control period from October 2017, NIE would be asked to submit to the UR two numbers as part of its network investment or capex proposals (we assume this is a new five-year control but nothing turns on this assumption about the duration of a future price control period):

(a) *Forecast network investment.* This is NIE's estimate of its expected network investment requirements for the price control period from October 2017 to September 2022.

(b) *Pre-funded costs.* This is an estimate of the value of network investment under *(a)* that does not need to be included as part of the calculation of price controls from October 2017 because it has already been included as part of the network investment requirements—and network investment strategy—that we have assumed for the purposes of setting the price control from April 2012 to September 2017.

5.159 The identification and deduction of the number in *(b)* is intended to provide protection to consumers against the risk that, in the future, they face charges which reflect forecasts of the costs of work that NIE needs to carry out in the period from October 2017 as a consequence of deferral or abandonment of projects that NIE planned to carry out before October 2017.

5.160 We do not consider the assessment of pre-funded costs under *(b)* a purely mechanistic exercise of comparing volumes of different types of network investments. It would be a partly qualitative exercise, drawing on information on how NIE has adapted its investment and asset management over time. The starting point might be that shortfalls against planned volumes should be considered as potential pre-funded costs, but NIE would have an opportunity to assess whether that is the case (eg such shortfalls would not lead to pre-funded costs if they have not increased future investment requirements, perhaps because circumstances changed or NIE addressed the need for the planned investment in a different way).

Clarity on planned deliverables as part of our determination

5.161 To implement the proposed approach, we need to clarify the assumptions on NIE's network investment requirements that underpin our price control determination. To meet this aim, our price control determination should specify the forecast network investments or planned deliverables that we use to calculate the price control and reconcile these with the overall allowance for capex.

5.162 These planned deliverables can then provide a reference point for the estimation of pre-funded costs at the next price control review.

5.163 We illustrate our proposed approach by reference to three examples from NIE's network investment plan that we have included in our cost assessment (they form part of the capex in Section 9). Table 5.2 provides a brief summary of these projects and how the planned deliverables included in our calculation of a new price control for NIE for the period to September 2017 could feed into the assessment of pre-funded costs as part of the determination of the new price control from October 2017. We provide further information on these examples in Appendix 5.3.

TABLE 5.2 **Illustration of proposed approach for selected network investment**

Brief summary and planned deliverable	*Implications for 2017 price control review*
NIE's asset management strategy includes an overhead line programme on a rolling basis according to specified cycles (eg refurbishment of each circuit on a 15-year cycle). This strategy implies, for example, an expectation that around 5,000 km of 11 kV overhead line will be subject to refurbishment and around 2,000 km will be subject to re-engineering (eg replacement of conductors) during a five-year period. BPI has supported NIE's proposed strategy. Planned deliverable would be an expected volume of 11 kV refurbishment and re-engineering (eg 5,000 km and 2,000 km respectively).	NIE would be expected to propose further overhead line refurbishment and re-engineering as part of its expenditure requirements from October 2017. If NIE's proposals involve significantly higher volumes of work, NIE should establish whether the additional volumes are required because of a shortfall in NIE's 11 kV overhead programme in the period to October 2017. If so, it should include the value of that shortfall in the calculation of pre-funded costs.
NIE's asset management strategy includes the gradual elimination, over several price control periods, of all 4-pole 11 kV and 6.6 kV substations. NIE considers that these substations pose safety risks. NIE's plan is to replace 190 of these substations with more modern and safe variants in the RP5 period. The figure of 190 reflects NIE's assessment of substations pose a high safety risk. BPI has supported NIE's proposed strategy. Planned deliverable would be replacement of 190 4-pole 11 kV and 6.6 kV substations with modern and safe variants.	If NIE proposes as part of its expenditure plans for the next price control period the replacement of another tranche of 4-pole 11 kV and 6.6 kV substations (as expected under its current strategy and view that these are unsafe), NIE should identify as pre-funded costs any shortfall between the actual volume of 4-pole 11 kV and 6.6 kV it has carried out in the period to October 2017 and the planned deliverable of 190 units. Alternatively, if NIE proposes at the next price control review that 4-pole 11 kV and 6.6 kV substations no longer need to be replaced and can be made safe through refurbishment, NIE should identify as pre-funded costs any planned refurbishment costs that arise from any shortfall between the actual volume of 4-pole 11 kV and 6.6 kV it has carried out in the period to October 2017 and the planned deliverable of 190 units (if it had replaced these as planned, there would be no refurbishment costs).
BPI's draft assessment of NIE's asset management requirements are that NIE will need to replace six of its 110 kV/33 kV transmission transformers in the period to October 2017. The BPI assessment specifies which transformers these are and is based on information on the condition of these transformers. Planned deliverable would be replacement of six 110 kV/ 33 kV transformers (and their auxiliary equipment) with flexibility to NIE as to which transformers these are.	If NIE proposes the replacement of 110 kV/33 kV transmission transformers (and auxiliary equipment) as part of its expenditure plans from October 2017, it should identify as pre-funded costs the value of any shortfall against the planned deliverable of replacing six 110 kV/33 kV transmission transformers (and auxiliary equipment) in the price control period to September 2017.

Source: CC.

5.164 We will need to obtain some further clarification from NIE on its plan (eg on the distinction between engineering and refurbishment of overhead line).

5.165 As part of the next price control review, the UR would need to review and, if necessary, revise NIE's estimates of pre-funded costs by reference to the asset management assumptions we used in the calculation of the price control to September 2017 and information on out-turn volumes.

5.166 There is a practical issue concerning the timing of work on the next price control review. Work by NIE and the UR to set a new price control to apply from 1 October

2017 will need to be done before full information is available on out-turn volumes and projects in the price control period to 30 September 2017. We envisage that the new price control from 1 October 2017 would be calculated on the basis of the best available forecasts of the out-turn volumes for the remainder of the existing price control period and that any shortfalls in out-turn volumes against those forecasts are taken into account in the use of any 'no double-recovery' principle in setting the subsequent price control.

Efficiency and flexibility in network investment

5.167 Our proposed approach is not intended to tie NIE to the delivery of a series of investment projects that it has planned or forecast as part of the price control review process. NIE would not face financial penalties simply for deviating from the investment plan used as part of the price control review.

5.168 If NIE carries out less network investment than envisaged in the plan used to calculate the price control, it could face financial consequences as part of the calculation of the subsequent price control. But these consequences would be of a more limited and forward-looking nature: NIE would only be financially exposed to planned network investment which was not done and which is still needed in the future.

5.169 NIE would have clear financial incentives to depart from its plan in a way that enhances the efficiency of its investment programme. For instance:

(a) Efficient deferral of planned investment. If NIE can defer planned asset replacement projects without increasing expected costs over the long term (and whilst still complying with statutory obligations, etc), it could expect to benefit financially. Examples of efficient deferral include cases where NIE can defer an investment without any increase in long-term costs, and also cases where NIE can defer investment where the financial benefits from deferral (eg annual financing costs

of investment) outweighs any additional costs arising from deferral (eg higher maintenance costs to keep older assets in service or a small possibility of having to replace an asset at relatively high cost in fault or emergency conditions). The opportunities for NIE to benefit financially from deferral would be conditional on the efficiency of the deferral. NIE would not have a financial incentive to defer planned investment projects simply to exploit features of the price control framework and increase its own profits.

(b) *Abandonment of unnecessary projects.* If NIE identifies a planned investment project that turns out to be unnecessary (eg replacement of transformer capacity that is no longer needed due to changes in the location of demand) it would benefit financially from abandoning that investment project, in line with our proposed sharing of cost savings determined by the cost risk-sharing mechanism.

(c) *Downscaling over-specified projects.* If NIE identifies that a planned investment project could be scaled down in size, without any adverse long-term impact, the proposal could provide NIE with a financial incentive for NIE to do so. For example, NIE might forecast reductions in the demands on its system in a specific location and that find it possible to meet asset replacement needs through the installation of a transformer with lower capacity than planned. NIE could explain how the installation of the lower-capacity transformer addressed the planned need for a higher-capacity transformer and exclude the underdelivery of the higher-capacity transformer from the calculation of its pre-funded costs.

(d) *More efficient way to meet need for investment.* If NIE identifies an alternative way to meet the need for a planned project by carrying out a different network intervention at lower cost, it would have financial incentives to do so. For example, suppose that NIE had identified in its investment plan that a category of substations was unsafe because of features of its design, and had planned asset replacement on safety grounds before the anticipated end of the economic life of these assets. Under our proposal, NIE would have financial incentives to find ways to address the safety more efficiently (eg some form of innovative asset refurbishment may be possible).

5.170 A common feature of the opportunities above is that they relate to NIE adapting its plan in a way that it means it carries out less network investment that anticipated in a particular area.

5.171 We have also considered the potential for NIE to adapt its plan in a way that it means it carries out more network investment than anticipated in a particular area. In some circumstances, NIE could carry out unanticipated investment without any adverse financial impact on NIE:

(a) Whilst parts of NIE's plan are built up from the identification of specific network assets that require replacement (eg a substation in a particular location), the planned deliverables that we would use to calculate the price control would relate to volumes of particular categories (eg replacement of six 110 kV/33 kV transformers). NIE would have flexibility as to which specific assets within each category to replace, and could reprioritize within categories according to changing conditions and new information. We consider that NIE's opportunities to reprioritize in this way will be substantial. In our cost assessment, we have made limited reductions to the volumes forecast by NIE. BPI's report for us on NIE's investment plan (see paragraphs 9.11 to 9.26) supports the view that some of NIE's planned investment, whilst reasonable on a long-term economic and engineering basis, will not be strictly required in the period to September 2017 to maintain services to current consumers and comply with legal obligations.

(b) We propose that our price control includes allowances for capex that falls under what NIE describes as fault and emergency work and reactive work. For these categories of investment, we do not plan to specify planned deliverables. In effect, these allowances provide a contingency for unanticipated investment.

(c) We propose that the allowances for distribution network load-related expenditure are not subject to the no double counting provision and NIE's actual investment in these categories would not form part of pre-funded costs for the next price control review. This provides further contingency.

(d) For some other elements of NIE's plan it is not practical, based on the information available to us, to specify planned deliverables in terms of volumes of investment for specific types of network intervention. This represents a significant element of NIE's overall capex allowance. NIE would be able to scale down its planned investment in these areas without any impact on the calculation of pre-funded costs at the next price control review. It reflects a limitation of our proposals to meet the intended purpose of protecting consumers from adverse financial consequences of investment deferment, but also provides a further financial contingency to NIE.

5.172 In other circumstances, it is possible that NIE may face an adverse financial impact from carrying out unanticipated investment. We can distinguish two scenarios:

(a) NIE might consider it necessary (eg due to safety obligations) to incur the un-planned investment and adapt its plan accordingly. Our proposal would not prevent NIE from adapting its plan in these circumstances. NIE's investors, would however, face some financial downside as a result of the unforeseen events that necessitate the change in plan.

(b) NIE might avoid a change in its plan that, whilst representing an efficiency improvement, would not be profitable for NIE. In this case, the economic effects our proposal would be to prevent NIE from adapting its plan.

5.173 In light of *(b)*, we accept that—compared with the 'do-nothing' option—our proposed approach is likely to reduce, to some degree, the extent to which NIE chooses to re-optimize its network investment plan over the price control period. However, for the reasons set out above, we consider that NIE would still have substantial freedom and incentive to adapt and improve its investment plan over the price control period in light of changing conditions and new information.

Interactions with cost risk-sharing mechanism

5.174 The implementation of a principle of no double-funding of deferred investment requires consideration of the cost risk-sharing mechanism discussed above in section D1. With such a mechanism in place, the extent to which NIE is ‘funded’ for costs it has incurred depends not only on the regulatory expenditure forecasts used to calculate the price control but also on NIE’s actual expenditure.

5.175 The approach envisaged would work in the most straightforward way if there is stability from one price control period to the next on the extent of cost pass-through under the cost risk-sharing mechanism. Unnecessary changes to the extent of cost pass-through should be avoided as far as possible.

5.176 If a change is made to the extent of cost pass-through in the next price control period, it would be appropriate to make an adjustment to the level of pre-funded costs to offset that change in order to achieve the underlying objective of no double-funding of deferred investment when viewed across multiple price control periods.

No financing adjustments in calculation of pre-funded costs

5.177 We have considered whether the calculation of the value of pre-funded costs to be netted off NIE’s investment requirements in setting the price control from October 2017 should include some allowance for the financing costs. We do not consider such an adjustment to be appropriate or consistent with the overall approach. The purpose of our proposal is to protect consumers from adverse financial consequences from investment deferral. The aim is not to remove from NIE’s RAB money that it did not actually spend, but rather to ensure that the subsequent price control does not expose consumers to additional costs for planned work that NIE avoided in the previous price control period.

5.178 Our proposed approach does not deal with the risk that the capex forecast used to set the price control is too high because it overlooks opportunities for efficient deferral of planned expenditure. Further, our proposed approach provides no protection to consumers against the risk that the price control is calculated to include an investment project that never actually needs to be done. We have sought to tackle these risks, as far as possible, through our assessment of NIE's capex requirements (see Section 9).

Annual reporting during price control period

5.179 The approach involves a significant administrative and regulatory burden. For instance, it relies on reliable records of the volumes of network investment carried out by NIE in each year of the price control period. However, much of this information is needed for other regulatory purposes. These include: *(a)* ensuring that there is better information available on NIE's unit costs and volumes at the next price control review; *(b)* supporting benchmarking analysis with GB electricity distribution companies; and *(c)* providing greater transparency on NIE's costs and investments to stakeholders.

5.180 The estimation of the value of pre-funded costs would be an important part of the new price control framework we established in the current inquiry. But it would not be used directly for several years. There is a risk that it is neglected and also that, when it does come to be needed, practical difficulties are found in calculating or verifying it.

5.181 To tackle this concern we envisage that NIE would be required to report to the UR during each year before October 2017 a provisional estimate of both forecast network investment for the subsequent price control period and the value of pre-funded costs. To support this, NIE would also need to report reliable information on out-turn volumes of network investment to date and volume forecasts for the remainder of the period to October 2017.

5.182 Reporting volume information on an annual basis, rather than leaving it to the next price control review, would help to reveal and resolve any problems or concerns as to the reliability and consistency of data reported.

5.183 Further, it would be important that the estimates of pre-funded costs (and the data which underpin them) are maintained for subsequent price control periods; it should not be reset to zero after each price control review. For instance, it is necessary to ensure that investment deferred from the price control running to September 2017 is not funded twice in either a new price control from October 2017 or a new price control from October 2022 (and so on).

5.184 The UR asked how our proposal would work with planned projects that were only partially completed by the end of the price control period. We envisage that it would work in the following way. If NIE has started a project but not completed it during the price control period, we would not normally expect NIE to include it in its investment plan for the next price control period. But if it does so, it should be included in the calculation of pre-funded costs. A feature of our proposed approach is that the exact time at which a project is carried out is not critical as long as a consistent approach is taken to development of the plan for the next price control period and estimation of pre-funded costs.

Risks to effectiveness from potential 'rebranding' investment projects

5.185 We recognize that our proposed approach may not be fully effective at addressing the risk that NIE defers planned investment projects to the detriment of consumers.

5.186 There may remain some opportunities for NIE to defer planned investment and yet impose additional costs on consumers during the subsequent price control period for that is needed as a direct result of that deferral. In particular, different project descriptions or changes in asset management practices might mean that at the subsequent price control review NIE can 'repackage' or 'rebrand' work in a way that limits the effectiveness of the approach.

5.187 We do not consider these issues fatal to our proposal. The comparison is not against a hypothetical ideal scheme, but rather with feasible alternatives. We consider that the proposal could still make a major contribution and that it is preferable to those alternatives.

Separate treatment of questions about compliance with statutory obligations

5.188 The aim of the scheme set out above is to protect consumers from adverse financial consequences in the event of investment deferral, not to prevent investment deferral (some of which may be efficient).

5.189 In some circumstances investment deferral might raise questions about NIE's compliance with its obligations to maintain and operate an efficient network and with its safety obligations. For instance, if NIE has identified a particular 11 kV four-pole substation as high risk and requiring replacement, there may be a question as to its compliance with its safety obligations if, five years later, it has still not replaced that substation.

5.190 The approach set out above is not intended to ensure NIE's compliance with its statutory and safety obligations. Although it is possible that the data reported as part of the approach might indicate areas of concern, any investigation of potential breach of safety and other obligations would be a separate matter.

Implications for regulatory framework at future price control reviews

5.191 The approach proposed above has implications for the cost assessment at the next price control review. As set out above, it would be necessary to take any pre-funded costs into account for the purposes of setting that establishing a new price control applicable from October 2017 that meets the policy of no double-funding of deferred investment.

5.192 The approach does not constrain other aspects of the way that a new price control is established from October 2017. NIE said that it was anxious that the adoption of such an approach did not jeopardize the effective operation of a price control model based on Ofgem's use of outputs and secondary deliverables for future price control periods. It is not our intention to jeopardize any potential use of such a model and we do not consider that the approach we have proposed would do so.

Comparison with UR approach

5.193 There are some similarities between the approach set out above and the UR's proposals for a volume adjustment mechanism under its output-measurable Fund 1 approach.

5.194 Both approaches involve financial adjustments calculated as part of the subsequent price control review in light of a comparison between the forecast volumes of network investment used to calculate the original price control and the volumes of network investment that NIE actually carries out during the price control period.

5.195 There are, however, a number of important differences. The purpose of the adjustments at the subsequent price control review under the UR’s proposals is to deny NIE financial benefits from any past deferral of planned investment. The purpose of the adjustments required under the approach set out in this section is to prevent consumers from exposure to additional costs that are attributed to any past deferral of planned investment.

5.196 The two approaches differ in terms of the financial consequences of NIE carrying out greater volumes than forecast for some categories of network investment.

5.197 The approach set out in this section would not allow NIE to offset the financial impact of greater than expected volumes in some categories of network investment (eg 33 kV overhead line refurbishment) with reductions to the volume of investment in other categories (eg 11 kV overhead line refurbishment). But it would allow flexibility for NIE to reprioritize within categories without any adverse financial consequences (eg to select which particular 11 kV circuits to refurbish or which particular 110 kV/33 kV substations to replace).

5.198 The UR’s proposed approach would provide a financial framework under which NIE could substitute between different categories of network investment in ratios relative to the regulatory assessment of the unit costs of work in those categories. This aspect of the UR’s proposals poses risks of providing NIE with perverse financial incentives to carry out more network investment than necessary for those categories of network investment where the regulatory unit cost allowance is such as to provide an attractive profit opportunity for NIE. The UR’s proposals for an embedded ‘reporter’ within NIE and an efficient spend clause seem a necessary part of its approach, to help mitigate these risks.

Comparison with Ofgem approach to network output measures

5.199 Both NIE and the UR told us that, whilst not feasible for our inquiry, for future price control reviews they would like to adopt an approach to the regulation of NIE's network investment that used Ofgem's approach of network output measures and secondary deliverables (eg asset health indices). We have considered how our proposals compare with Ofgem's approach.

5.200 Our proposed approach shares some similarities with Ofgem's approach to network investment. For instance, Ofgem said the following in its initial proposals for a new price control for National Grid Electricity Transmission and National Grid Gas:[17]

> If a company achieves above target or below target against the NOMs [network output measures] target, it would need to justify this variance in its RIIO-T2 business plan. We would still take the RIIO-T1 NOMs target as an opening position when setting out the allowance for the company to deliver its RIIO-T2 NOMs target. This ensures that any under-delivery is not funded twice, and that any over-delivery receives funding.

5.201 Put differently, Ofgem proposed to calculate the subsequent price controls for National Grid (these controls are called RIIO-T2) in a way that did not provide it with any additional funding for shortfalls or under-delivery against what was envisaged in setting its initial price controls (RIIO-T1).

5.202 However, there are important differences with the approach above. In its submissions to us, NIE sought to stress that our approach was different in important ways.

[17] Ofgem RIIO-GD1: Supporting document: Outputs, incentives and innovation, July 2012, p109.

5.203 Ofgem's approach seeks to measure underdelivery by reference to measures of the condition of specific network assets, whereas under the approach above the measure of underdelivery would be made by reference to the volumes of planned network investment projects. The Ofgem approach pays more attention to the benefits from planned investments (eg improvements to the condition of network assets) than to the planned investment projects themselves.

5.204 Using measures of asset condition may provide for greater flexibility for the regulated company to substitute and reprioritize network investment between different categories of work than the approach set out above. But neither NIE nor the UR considers it feasible to provide the type of information that the Ofgem approach relies on within the time frame of our inquiry.

5.205 NIE argued that another difference between our proposed approach and Ofgem's was that Ofgem would 'intervene' in more limited circumstances, where it found a material 'network outputs gap'.

5.206 Ofgem's approach is still evolving and its use of asset condition data has not yet been tested through one complete price control period. The UR suggested that it was possible that Ofgem made adjustments to GB DNOs' allowed revenues not only in light of data on asset condition but also in light of comparisons of the volumes of asset replacement projects delivered against the volume forecasts at the previous price control period. The UR highlighted that Ofgem's approach also involved detailed reporting of actual replacement volumes and unit costs.

5.207 Similarly, we recognize a possibility that the differences between the approach that Ofgem takes in the future and the approach discussed above (or the volume adjustment mechanism proposed by the UR) may turn out to be less substantial than they appear from the documents published by Ofgem to date.

UR's submissions on the approach

5.208 We shared with the main parties our initial analysis and options in relation to the risks to consumers from investment deferral.

5.209 The UR compared our proposed approach with the volume adjustment mechanism it had proposed. It said that the two schemes were 'more similar than they are different' and that both were far superior to the other options we had identified.

5.210 Nonetheless, the UR said that it preferred its original proposal for the following reasons:

(a) Our proposed approach does not prevent NIE from earning considerable profits from proposing an unnecessary project and then cancelling. The UR said that its proposed approach would prevent NIE from profiting from the cancellation of planned capital investment.

(b) Our proposed approach would consciously give NIE a financial reward for deferring planned investments. The UR said that there could be a large scale of deferral and that NIE could profit between £1 and £10 for every £100 of capex that it deferred.

(c) Our proposed approach would fail to protect consumers from 'instances of outright double-counting'. The UR said that 'insistence that NIE T&D should only be paid for completed and verified volumes is the only way to ensure that consumers don't pay twice'.

(d) Our proposed approach would be vulnerable to the 'rebranding' issue we raised above and may not be fully effective.

5.211 We do not agree that these points indicate the superiority of the UR's proposals.

5.212 Points *(a)* and *(b)* actually reflect desirable incentive properties of our proposal. Because NIE could profit from the cancellation of planned capital investment projects, it would have a financial incentive to cancel projects that turn out to be unnecessary. Because NIE could profit from deferral of planned projects, it would have a financial incentive to defer planned investment projects where it is efficient to do so. The cost risk-sharing arrangement that we have proposed in section D1 means that consumers would benefit from cost savings achieved by NIE in this way.

5.213 Points *(a)*, *(b)* and *(c)* also reflect the risk that the upfront expenditure forecast that we use to calculate the price control for NIE is too high. We accept the existence of this risk but consider the UR's proposed approach a disproportionate response to it which would have adverse effects for NIE's efficiency of operations and investment. We have sought to mitigate the risk that the upfront expenditure forecast is too high through our cost assessment work described in Sections 7 to 10.

5.214 We accept the existence of concerns under point *(d)* but we do not consider them sufficient to prevent our proposal from being the best of the feasible options. We do not expect that there would be systemic opportunities for NIE to escape the intention of the proposal through such rebranding, especially when the scheme does not apply mechanistically and instead involves an assessment of pre-funded costs by NIE which would then be reviewed by the UR.

NIE's submissions on the approach

5.215 NIE provided a detailed response to our preliminary work on the approach proposed above. NIE raised the following concerns:

(a) The proposal would remove any incentive for NIE continuously to optimize the network in a way that both met outputs and drove down total cost for the long-term benefit of consumers.

(b) The proposal provided limited opportunity for NIE to reoptimize its network and adapt its investment in light of new information, external factors and new technology.

(c) The proposal would not provide a mechanism for NIE to be fully remunerated for investment that was not anticipated in the investment plan used to calculate the price control.

5.216 NIE proposed a variant on our proposal, under which NIE could defer 10 per cent of the volumes in each investment category without any adverse financial consequences at the next price control review (though NIE suggested that a different threshold could be used). NIE said that this would provide protection to NIE against unanticipated investment needs. It told us that it would allow it to incur unanticipated expenditure that enabled it to adopt more cost-effective solutions. It said that the variant would provide assurance that the majority of planned deliverables in all categories of investment would be delivered.

5.217 NIE's submission also explained why its investment plans might change over time and the need for unplanned network investment.

5.218 We consider NIE's claims on points *(a)* and *(b)* above to be overstated. As discussed above in paragraphs 5.168 to 5.174, NIE would have clear financial incentives to abandon or downscale planned projects that are not necessary and take opportunities to defer planned investment where this is efficient.

5.219 Nonetheless, we accept that—compared with a ‘do-nothing’ option—there is some risk that—compared with the do-nothing option—our proposed approach could reduce, to some degree, the extent to which NIE would choose to reoptimize its network investment plan over the price control period. However, for the reasons set out in paragraphs 5.168 to 5.174, we consider that NIE would still have substantial freedom and incentive to adapt its investment plan over the price control period in light of changing conditions and new information. We consider that any residual limitations on NIE’s flexibility would be outweighed by the contribution that our proposal would make to the serious concerns that we have identified about investment deferral to the detriment of consumers.

5.220 We have considered NIE’s proposed variant. We are not persuaded that it would represent a better approach.

5.221 NIE’s variant would not protect consumers against the first 10 per cent of investment deferral in each category. We do not consider such deferral immaterial, especially if experienced across a number of different investment categories. Although NIE envisaged in its submission that this feature of its variant would allow it to reoptimize its network or investment plan by spending more in other areas, there is no link or mechanism to ensure that any money that NIE saves from deferral is used for that purpose; NIE might, instead, use the saving to provide higher profits to shareholders. We do not consider the variant proposed by NIE to be a reliable way to ensure that NIE has financial incentives to reoptimize its network which could help offset the reduced protection to consumers against investment deferral.

5.222 NIE’s submission raises concerns about the financial risk properties of our proposal, which it considered to involve excessive downside risk. We have considered whether NIE’s variant might be appropriate for another purpose, which is to change the balance between the potential financial downsides to NIE under the price control framework and the potential financial upsides. We do not consider this necessary, particularly in light of the discussion in paragraphs 5.168 to 5.174. In particular, even without NIE's variation there would be flexibility and contingency within the price control framework for NIE to limit its downside financial exposure and NIE would have opportunities for financial upside.

5.223 It is difficult to gauge the overall balance of upside and downside risk to NIE under our proposal and under NIE's proposed variant. We are not persuaded that NIE's variation is more appropriate in terms of the balance of risk. NIE's proposed variation has the further disadvantages that it is less effective at meeting the original objective of the proposal (protection to consumers in cases of investment deferral) and it is more complicated. Overall, we consider our proposal to be more appropriate than NIE's proposed variation.

D4: Investment projects for distribution network load-related expenditure

5.224 This section concerns the possibility of including mechanisms or provisions in the price control framework to allow some flexibility to NIE's revenue restriction and RAB in light of uncertainty about NIE's expenditure requirements for work to increase the capacity of its distribution network. It relates to the UR's proposals for load-related expenditure under Fund 2.

UR's and NIE's proposals

5.225 The UR's proposals are described in Appendix 5.1. In short, the UR proposed that it should be able to adjust NIE's price control during the price control period to make case-by-case approvals for additional expenditure to increase distribution network capacity and that NIE should also be able to carry out such expenditure without pre-approval and be remunerated for it if it could subsequently demonstrate that it was necessary and efficient. The UR's proposed reporter would support the UR on project approval and review of expenditure projects that were not approved in advance. The UR proposed that NIE update and provide information on its asset management strategy to help the UR's decisions on whether to approve funding.

5.226 In contrast, NIE proposed that there should not be any ex-ante or ex-post regulatory approval process during the price control period in relation to projects to increase distribution network capacity. NIE's proposals would involve a fixed upfront allowance that would be intended to cover its expenditure requirements to increase capacity on the distribution network to accommodate additional load. NIE's concerns with the UR's proposals include risks of regulatory micro-management, lack of flexibility and concerns about the ex-post nature of the reviews of investment projects that NIE carries out.

5.227 NIE did not consider it possible to use the unit cost forecasts relating to asset replacement to set additional allowances for distribution of load-related expenditure. NIE argued that unit costs for asset replacement could not be used for load-related expenditure under the UR's proposed Fund 2. This was because asset replacement involved replacement of selected assets and could not be equated to the cost of building a new overhead line.

5.228 In its rebuttal of NIE's submission to us on priorities for the inquiry, the UR argued that NIE's alternative proposals for load-related distribution projects would increase our workload in this inquiry:

> Accepting NIE T&D's proposal would increase the difficulty of the Commission's task in relation to capex by requiring the Commission to identify to an appropriate degree of accuracy an ex ante allowance for almost all capex, including for highly uncertain projects related to

> potential demand growth which we proposed for inclusion in Fund 2. This would mean gathering sufficient data to make an accurate once-and-for-all determination whether the various projects proposed by NIE T&D are really necessary and represent value for customers' money backed up by evidence of customer willingness to pay.

5.229 The UR continued as follows: 'We do not think it can be in the public interest in the circumstances of this inquiry to set an ex ante allowance for non-renewables investment where there is neither certainty of need nor accountability for deliverables.'

5.230 NIE's proposed approach would place a greater requirement on upfront expenditure forecasts for load-related expenditure, whereas the UR's approach involves an element of 'wait and see'.

5.231 In terms of the implementation, UR proposals were that there would be no adjustments to NIE's maximum regulated revenue during the RP5 price control period for any additional load-related expenditure beyond that set in the original allowance. Instead, if further projects are approved by the UR, NIE's revenues would be adjusted from the RP6 price control period. The UR's view seems to be that in the interests of tariff stability, adjustments are made during RP6.

5.232 NIE said the following in response to the UR's comment that revenue adjustments for additional load-related projects under Fund 2 would be delayed until RP6 for the purposes of tariff stability:

> NIE questions whether it is appropriate to defer any revenue adjustment to RP6. While that might result in tariff stability during RP5 it holds the promise of a very substantial increase in tariffs in RP6. It is doubtful whether such an approach is in the best interests of customers. It also

creates the risk that the RP6 price control review will be doubly onerous, as it will entail a major ex post review of NIE's capex works from RP5, as well as a forecast of its capex needs for RP6.

Options identified for load-related expenditure on distribution network

5.233 We identified four main options:

(a) Set an upfront allowance based on a forecast of the expenditure NIE will need to incur, over the price control period, to accommodate localised load growth on its distribution network. This would include an allowance for specific anticipated investment projects that are considered necessary and some forecast or contingency to cover other potential projects that might be needed.

(b) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a provision for NIE to come to the UR and seek adjustments to its maximum regulated revenue allowance and RAB to provide for further investment projects to increase capacity of the distribution network that become necessary during the price control period. As part of the approval process the UR would specify an upfront allowance for each allowed project before it is carried out.

(c) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a provision for NIE to be compensated through future revenue controls and RAB for any expenditure on distribution network capacity that it incurs and which it can subsequently justify to the UR as necessary and efficient expenditure. The amount of compensation would not necessarily provide full compensation for the costs it incurs. Instead a cost allowance for work that NIE has done under this provision would be calculated by reference to the unit costs used to set the price control (eg unit costs for asset replacement work or predicted load-related network investment) multiplied by the volume of work that NIE has undertaken.

These unit costs would not reflect local conditions. NIE would be entitled to no remuneration in relation to increase in the capacity of the distribution system carried out by NIE that the UR does not consider to have been necessary.

(d) Set an upfront allowance based on forecasts of the costs of specific investment projects that we consider are (or will be) necessary and supplement this with a mechanism to automatically increase NIE's revenue control and RAB according to any additional investment carried out by NIE to increase distribution network capacity. The mechanistic adjustments to NIE's revenue control and RAB would be calculated by reference to unit cost allowances specified at the price control review and would be conditional on any increases to NIE's distribution network capacity being compliant with asset management documentation that explains in detail how NIE will make decisions on the need for additional investment in its distribution network capacity. This would refer to established network planning standards and NIE's statutory obligations and would also clarify how NIE intends to interpret aspects of these when making practical decisions. Subject to NIE's compliance with this documentation, the scope for regulatory intervention on an 'ex-post' basis would be limited to any inefficient spend clause that applies more generally (see section D2).

5.234 Option *(a)* represents NIE's proposals.

5.235 Options *(b)* and *(c)* contain elements of the UR's RP5 proposals for distribution network load-related expenditure (the UR's RP5 proposals were for a combination of *(b)* and *(c)*). Under options *(b)* and *(c)* there is a potential optional role for the reporter envisaged by the UR to help the UR with upfront project approvals or backward-looking assessments of whether investment carried out by NIE was necessary.

5.236 We identified option *(d)* as a variant on options *(b)* and *(c)* which would provide some flexibility within the price control arrangement without requiring project-by-project review and approval by the UR and without exposing NIE to uncertainty about whether projects would be approved by the UR ex post.

5.237 We shared the options above with the main parties as part of our inquiry.

5.238 The UR said that it would strongly prefer either option *(b)* or a combination of *(b)* and *(c)* with NIE having the ability to choose between seeking upfront approval from the UR for additional investment or relying on ex-post regulatory approval of investments it has already carried out. The UR did not expect it to be feasible to develop the necessary asset management documentation for option *(b)* and that even if this could be done the UR would be worried that NIE's spending could reflect documentation that presented an inefficient approach to asset management. The UR also submitted that option *(c)* on its own would expose NIE T&D and consumers to too much uncertainty.

5.239 NIE's Statement of Case had proposed option *(a)*. Of the other options, NIE told us that it had a strong preference for option *(d)* under which load-related expenditure would, if justified by reference to documented asset management criteria, lead to additional revenues calculated on the basis of unit cost allowances established as part of our determination.

NIE's draft asset management documentation

5.240 In relation to option *(d)*, NIE provided us with an initial draft of criteria for making additional investment decisions for distribution-load-related investment, and a worked example of the application of these criteria.

5.241 The UR told us that NIE's draft documents were too narrow in scope and insufficiently specific to form the basis of an arrangement under which NIE would self-certify expenditure for recovery from customers. In particular, NIE's draft documents did not make investment conditional on any cost-benefit analysis. The UR also thought that NIE's documents would allow it to err on the side of making expensive investments rather than potentially more efficient solutions, such as relying on the diversity of peaking times between different loads; dynamic line ratings; demand response; or distributed generation.

5.242 We think that NIE's draft documentation provides helpful guidance on how NIE identifies capacity shortages on its network and how it designs investment proposals to address such shortages. Publishing such documentation could be helpful to energy consumers to use as a benchmark to design alternative solutions such as demand response and distributed generation.

5.243 However, our review of NIE's draft documentation identified barriers to its use as the basis for a price control adjustment mechanism:

(a) We agreed with the UR that NIE's documentation did not take sufficient account of ways of addressing capacity limitations that did not involve network investment, such as demand response and distributed generation.

(b) NIE's documentation only covered investment to meet additional demand. We were not clear on what basis, if any, it might be used in respect of the significant amounts that NIE said it might need to spend to accommodate additional renewable generation.

(c) We identified a risk that NIE's documentation could, in some cases, conflict with the security of supply standard, currently P2/5. This could mean that compliance with the documentation would place NIE in breach of its obligations (unless the UR granted it a derogation).

(d) We did not have a set of agreed unit costs covering the investment items that might be justified by the criteria, particularly for 33 kV and primary substation investments.

Our assessment

5.244 Our view is that options *(b)* and *(c)* would involve too great a degree of regulatory micro-management in NIE's business and would carry an unduly high regulatory burden.

5.245 We were initially attracted to option *(d)* as a means to tackle these specific disadvantages of options *(b)* and *(c)*. However, we did not think that NIE had submitted sufficiently precise criteria to form the basis of a mechanistic scheme to adjust investment allowances. This view reflects the inherent complexity and diversity of distribution network investment projects and not necessarily shortcomings in NIE's draft documentation.

5.246 A further problem with option *(d)* is that we would need to specify upfront cost figures that can be used to calculate a mechanistic allowance. Whilst we could base these in part on the costs of projects that are already anticipated and included in NIE's forecasts, it would be more difficult to establish costs for other potential projects. There is also a risk that if the cost allowance for additional capacity under the mechanism is higher than NIE's actual costs, this could provide NIE with perverse financial incentives to carry out projects that are not necessary. We did not consider the envisaged asset management documentation and inefficient spend clause likely to be sufficient to prevent NIE from acting on those incentives.

5.247 We reconsidered option *(a)* in light of the drawbacks of the other options.

5.248 NIE's updated forecast for distribution load-related expenditure was £24.6 million over the RP5 period.[18] Of this, our consultants BPI recommended that we allow £22.3 million based on the information currently available. BPI expected that further projects might be needed over the period to 30 September 2017, although these were difficult to forecast. The difference between the two is £2.3 million. In view of the scale of this difference, and the drawbacks of the other options above, we propose option *(a)* with an upfront allowance set for the period to 30 September 2017. As with other areas of expenditure, any difference between NIE's out-turn expenditure and this forecast will be subject to the cost risk-sharing mechanism described in section D4.

5.249 We do not propose to apply our proposals from section D3 in relation to investment deferral to this aspect of our cost assessment.

D5: Investment projects to increase transmission system capacity

5.250 This section concerns the possibility of including provisions in the price control framework to allow a within-period adjustment to NIE's revenue restriction and RAB calculation in light of substantial uncertainty about NIE's expenditure requirements for work to increase the capacity of its transmission system. It considers, in particular, the UR's proposals for capex Fund 3, which would allow for project-by-project approval of transmission network investments by the UR during the price control period.

UR's proposals and NIE's submissions

5.251 The UR describes its Fund 3 proposals as follows:[19]

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[18] NIE Statement of Case, p413.
[19] UR Statement of Case, UR-4, p12.

Fund 3 is intended to cover large projects for which there is even greater uncertainty than in Fund 2, both as to timing and cost. This covers, in particular, smart metering and investments in the network required to accommodate the expansion of renewable energy that is anticipated to take place in order to satisfy EU renewable energy targets. The operation of this fund is straightforward: there are no allowances at this stage, but NIE T&D has complete freedom to present proposals for projects at any stage in RP5 and they will be approved to the extent that they are necessary and efficient. This approach insulates NIE T&D from essentially all of the (substantial) risk associated with these projects.

5.252 The UR told us that its intention was that its Fund 3 proposals should cover projects to address government policy related to reducing carbon emissions, and in particular the national action plans for renewable generation and energy efficiency. The UR said that the special treatment of these projects was required because of the extent of uncertainty at this stage, both as to whether projects were needed in the price control period and also to their costs.

5.253 In August 2012, the UR issued a consultation paper on the approach it would take in dealing with requests for approval from NIE during the price control period.[20]

5.254 NIE supported the UR's proposed approach of setting no upfront allowance for certain large projects and instead adjusting NIE's price control and RAB as part of a project-by-project approval process. NIE raised some concerns about the process

[20] The UR 'Approval criteria and incentive mechanisms for RP5 Fund 3 - Investments for Renewable Electricity', August 2012.

and risk of delays. NIE proposed that the UR's proposals for Fund 3 be applied but with some modifications:[21]

(a) a clearly specified process for UR approval of investment projects proposed by NIE;

(b) clearly specified rules for the regulatory treatment of approved projects (eg in relation to incentives);

(c) the inclusion within Fund 3 of the Ballylumford switchboard project; and

(d) the exclusion of work relating to smart grid development from Fund 3.

5.255 We consider issues relating to smart grids separately in section D6. We focus here on transmission investment projects.

Regulatory precedent

5.256 The use of a project-by-project approval regulatory process for major transmission network projects is familiar from Ofgem's regulation of electricity transmission companies in GB. As part of new price controls for National Grid Electricity Transmission and the two transmission network companies in Scotland, Ofgem introduced its Strategic Wider Works mechanism, which allows the network companies to bring forward projects for regulatory approval during the eight-year price control period.

5.257 For National Grid, Ofgem's approach also allows National Grid to be remunerated for some investment without Ofgem pre-approval, if investment to increase capacity is consistent with a network development policy that National Grid has developed and had approved for Ofgem. We do not consider this approach feasible within the timescale of our inquiry. We suspect that it would also have practical problems in Northern Ireland that arise from the separation between *(a)* system operation and transmission planning and *(b)* transmission asset ownership.

[21] NIE Statement of Case.

Risks under UR's proposals

5.258 We have identified several risks of the UR's Fund 3 proposals which we might seek to address through the design of a project-by-project approval process:

(a) a risk that NIE is funded twice (or seen to be funded twice) if there is not a clear definition of what aspects of NIE's network investment is to be funded through an upfront allowance as part of the price control and what is funded through a project-by-project approval process;

(b) risk of delays to delivery of worthwhile projects to increase capacity of transmission system;

(c) missed opportunities for greater use of competitive processes for the planning, design and delivery of investment projects to increase the capacity of the transmission system, including transmission capacity within Northern Ireland and capacity between Northern Ireland and the Republic of Ireland or GB; and

(d) the potential for distortions to NIE's network investment, working practices and cost reporting if it faces different marginal financial incentives for underspend and overspend on these projects compared with other parts of its expenditure.

Our assessment

5.259 There is substantial uncertainty about NIE's investment requirements to increase the capacity and capabilities of its transmission system. We propose that NIE's price control Licence conditions include a provision to allow the UR to determine adjustments to NIE's maximum regulated revenue and RAB to allow for the costs of necessary investments of this nature. We have taken account of the regulatory precedent for such arrangements and the parties' support for this type of provision.

5.260 The practical operation of this arrangement would be conditional on NIE making applications to the UR for specific projects. We propose that NIE is placed under an obligation to develop and bring to the UR proposals for relevant investment projects that are in consumers' interests, drawing on input from SONI, and to provide the UR with the information necessary to assess NIE's application (in so far as it is available to NIE).

5.261 Any adjustments that the UR makes to NIE's maximum regulated revenue and RAB should be limited to what is necessary to allow for the expected efficient costs of delivery of the investment project, in light of the UR's review of these costs. We propose that the cost risk-sharing mechanism set out in section D1 should apply in relation to out-turn costs for any projects approved. The same cost risk-sharing percentage would apply as for other elements of NIE's opex and capex to avoid unduly distorting NIE's working practices and cost reporting and to limit complexity of the regulatory framework.

Scope of provision

5.262 Our proposed provision is intended to cover projects relating to NIE's electricity transmission network that increase its capacity or capability. This includes investment to expand NIE's transmission network to accommodate renewable generation. But we do not consider it necessary or appropriate to limit it to projects attributable to renewable generation or government energy policy initiatives.

5.263 With the anticipated transfer of transmission planning responsibilities to SONI, we propose that a prerequisite for any project to be within scope of the provision is that the investment is requested by SONI. It would not make sense for NIE to propose increases to transmission network capacity to the UR for approval if SONI does not consider the project an appropriate development of the transmission network.

5.264 Our proposed provision does not include asset replacement expenditure. Our upfront cost assessment from Section 9 is intended to cover NIE's asset replacement needs in the period to 30 September 2017 (as well as some projects to increase the capacity or capability of NIE's transmission system for which the need has already been established).

UR's decisions under the provision

5.265 It will be for the UR to take appropriate decisions under the provision. We expect that the UR will need to consider the following as part of its decision-making:

- *(a)* whether NIE has already received some funding in relation to the project as part of the expenditure allowances used to calculate NIE's price control;
- *(b)* an assessment of whether a proposed project is in the interests of consumers. That project assessment should include consideration of alternative options including (i) operational measures that can avoid or delay the need for network investment and (ii) the possibility of delaying a decision on the proposed project until more information is available on its need and appropriate design;
- *(c)* a determination of an appropriate upfront cost allowance, against which NIE would face financial exposure under the cost risk-sharing mechanism; and
- *(d)* the potential use of agreed delivery dates or milestones for the project, with financial consequences for NIE for late delivery.

5.266 NIE raised concerns about possible delays to necessary transmission investment projects from delays in the approval process involving the UR. Whilst we recognize that delays could operate against the interests of consumers and that prompt decisions are part of good administration, we have not sought to address these concerns as part of our determination. Our inquiry is focused on NIE's price control Licence conditions and not the overall regulatory regime in Northern Ireland. Whilst we could seek to make the UR's ability to veto projects proposed by NIE time-limited, this would not necessarily ensure that the UR's decisions are as swift as possible:

the UR could simply veto within the permitted time frame any proposals for which it does not consider that it has had sufficient time or information to consider properly.

Potential for competition

5.267 Our proposed inclusion of a provision within NIE's price control Licence conditions to allow NIE to be tasked with developing additional transmission investment in Northern Ireland does not mean that NIE is necessarily best placed to carry out that investment. The anticipated allocation of greater transmission investment planning responsibilities to SONI creates new opportunities for the involvement of parties other than NIE. The construction, ownership and maintenance of electricity transmission infrastructure in Northern Ireland is not a natural monopoly for which the only plausible provider is NIE.

5.268 We would expect the UR to consider the potential for projects to be developed and subsequently owned and maintained by a party other than NIE (eg a party appointed by SONI or the UR through a competitive process). Whilst there would be administrative costs and practical difficulties to overcome in the establishment of more competitive arrangements in Northern Ireland, these are also potential benefits to be realized from competition.

Ballyumford switchboard

5.269 NIE argued that Ballyumford switchboard should also be included under the UR's Fund 3 approach. NIE's argument was simply that the 'scale of uncertainty as to the cost of this project is so great that this should be subject to specific approval under Fund 3'.[22] On its own, uncertainty about cost does not seem sufficient to treat this project outside the main price control and subject it to project-by-project approval. We have included this project within our upfront cost assessment.

[22] ibid, p52.

D6: Smart grid initiatives

5.270 This section concerns the UR's proposals for its proposed Fund 3 capex arrangement to also include the potential for the UR to make a within-period determination to approval additional revenues for NIE for smart grid initiatives (eg smart grid trials). These elements of the UR's Fund 3 proposals concern different issues to investment to expand capacity of the electricity transmission system.

5.271 The UR told us that the only way to ensure that these initiatives were taken forwards, given the lack of certainty on what was to be delivered or its costs, was to adopt an approach of project-specific approval during the price control period.

5.272 NIE did not support the inclusion of smart grid expenditure in the UR's Fund 3 proposals. Instead, NIE proposed that smart grid initiatives were considered as part of the determination of an upfront capex allowance. We have included potential smart grid initiatives as part of our upfront cost assessment.

5.273 We have not identified a need to include smart grid initiatives in a project-by-project approval process.

D7: Electricity meter investment and smart meter programme

5.274 This section concerns the treatment of capex related to meters as part of the price control. The UR proposed a volume adjustment mechanism—what Ofgem might call a volume driver—for capex that NIE incurred to replace, recertify and install meters. The UR's proposals for metering capex fall under its Fund 2 proposals and are described in more detail in Appendix 5.1.

5.275 We also discuss potential implications of the smart metering programme in Northern Ireland. We use the term 'conventional meters' to refer to electricity meters that are not smart meters; these include keypad meters. Conventional meters are the main focus of our inquiry in relation to metering capex.

Conventional meters: options identified

5.276 There is uncertainty about the amount of conventional meter installation, replacement and recertification that NIE will need to carry out in the period to 30 September 2017. We have identified three potential options that we could take in relation to NIE's costs for meter installation, replacement and recertification:

(a) Make an upfront regulatory forecast of NIE's total costs of meter installation, replacement and recertification and use this as part of the calculation NIE's RAB and allowed revenues for the price control period. In line with treatment of other expenditure, the cost risk-sharing mechanism above (if any) would apply in relation to any differences between NIE's actual costs for meter installation, replacement and recertification and the upfront regulatory forecast.

(b) Make an upfront regulatory forecast of NIE's total costs of meter installation, replacement and recertification and combine this with an adjustment mechanism to vary NIE's allowed revenues and RAB according to differences between (i) the actual volumes of installation, replacement and recertification that NIE carries out in each year of the price control period and (ii) the forecast volumes that were used for the calculation of the upfront regulatory forecast. The intention would be for NIE to be remunerated on a cost per unit basis for each unit of meter installation, replacement and recertification it is required to carry out. The unit costs for different categories of meter work would be established as part of the price control determination.

(c) Determine meter costs as an excluded service for the purposes of the revenue control and provide no upfront funding for the estimated costs of meter replacement and meter installation. Instead require NIE to set charges to suppliers for meter work that NIE can justify as reasonable in light of costs and the charges for

comparable services by other companies. If NIE was found by the UR to have set charges at levels that were not compatible with this requirement, it could require NIE to reduce its charges to ensure compliance with the price control Licence conditions.

5.277 The first option reflects NIE's original proposals in its Statement of Case. The second option reflects the UR's proposals. NIE's proposals would be simpler but would expose consumers (and NIE) to greater cost forecasting risk. The UR's proposed approach would help reduce risks relating to uncertainty as to the volume of meter replacement. It might carry some risks of perverse financial incentives if NIE has flexibility over the timing and volume of work and if its costs vary significantly from the unit costs used to set the volume adjustment mechanism.

5.278 The third option would bring greater transparency to meter costs and provides an alternative to *(b)* as a means to avoid exposure to an uncertain upfront forecast of the volume of meter work. But it would involve a substantial change to the price control arrangements for NIE and also to the commercial arrangements within the Northern Ireland electricity system because NIE does not currently charge suppliers directly for meter-related services. The UR told us that this might require modifications to electricity supply licences and that it would be willing to consider this option in the future as part of the deregulation of domestic supply prices. The UR did not consider this option feasible for the purposes of our determination of a new price control for NIE: 'While we consider that it would be something that we should investigate further in the context of the deregulation of domestic supply prices in the future, however, we are concerned that it would be impossible to implement within the time frame required for this price control period.'

5.279 Following sight of the options identified above, NIE told us that it acknowledged the potential benefits of option *(b)*. It said that it expected there to be significant timing issues associated with option *(c)* including issues relating to the need for adequate consultation on the change.

Conventional meters: our assessment

5.280 We propose the approach under *(b)* above, in which an upfront forecast would be combined with adjustments in light of out-turn volumes according to unit cost allowances that we will specify upfront. This helps address substantial uncertainty about volumes, especially in relation to meter certification. The approach under *(c)* has attractions but does not seem feasible for our inquiry.

Potential implications of smart meter programme

5.281 A further complication that arises in relation to the expenditure that NIE will need to incur in relation to metering activities is the potential introduction of smart metering. DETI announced its decision to proceed with a roll-out of smart metering in July 2012, with the detailed arrangements for the roll-out to be consulted on by the UR.[23]

5.282 The UR proposed the inclusion of costs relating to smart metering as part of its proposed Fund 3 mechanism (see Appendix 5.1). The UR said in its final determination that the purpose of including smart metering in its Fund 3 proposal was to ensure that NIE could undertake these activities without having to wait until the next price control review. NIE's Statement of Case did not raise concerns with the inclusion of smart metering within the UR's Fund 3 proposals but questioned the need for NIE to demonstrate the benefits of smart metering as part of any regulatory approval process.

[23] ibid, p58.

Smart meters: options identified

5.283 The submissions of both NIE and the UR confirmed that there was not sufficient information available now on the timing and nature of the smart metering programme in Northern Ireland to provide an upfront regulatory forecast of NIE's smart metering costs in the period to 30 September 2017. In view of this, we have identified the following two options:

(a) Make no special provision within the Licence for adjustments to NIE's revenues and RAB in relation to smart metering. Instead recognize the potential for such adjustments either through the change of law provision in the existing Licence conditions (COL_t) or through an agreement between the UR and NIE on a Licence modification.

(b) Include a mechanism within the Licence to allow the UR to make a determination that varies NIE's revenue, unit cost allowances and RAB in light of an upfront assessment of the estimated net cost impacts on NIE of an agreed smart meter programme.

Smart meters: our assessment

5.284 NIE told us that its preference was for a Licence modification under *(a)*. NIE said that it would be important for the CC to contain an express acknowledgment that this was the process that the CC expected the UR to follow in order to permit NIE to recover the costs in relation to smart metering.

5.285 The UR suggested that a potential drawback of approach *(a)* was that Licence modifications would require the agreement of NIE, which could introduce delays and a risk of another reference to the CC. The UR said that it would be concerned that a reference to the CC would be disproportionate for the single issue of the treatment of smart metering in NIE's price control. However, if NIE expects to incur additional costs as a result of new obligations that have been placed on it in relation to smart meters, it would be in NIE's interests to work constructively with the UR to agree Licence modifications to increase its maximum regulated revenue to cover those additional costs.

5.286 What the approach under *(a)* would not allow is for the UR to place additional obligations on NIE in relation to smart metering without NIE's consent. We do not consider that the flexibility for the UR to place additional obligations on NIE without NIE's consent is part of the modifications that we need to make to NIE's price control Licence conditions as part of our inquiry. We would expect that other elements of the legislative and regulatory framework would be available to ensure that NIE plays an appropriate role in the smart meter programme in Northern Ireland.

5.287 We propose not to make any Licence modifications specifically to accommodate potential changes in relation to smart metering. Instead, if changes are needed to NIE's maximum regulated revenue before 30 September 2017, we would expect the UR and NIE to make use of either the change of law provision in the existing Licence conditions (which we propose to retain) or a Licence modification.

D8: Pass-through of part of connections charges to NIE's RAB

5.288 This section concerns the UR's proposals for the treatment of certain costs relating to charges for new connections to NIE's network.

UR's RP5 proposals

5.289 In its final determinations, the UR identified around £37 million of costs that would be subject to cost pass-through, subject to an efficient spend clause, which relate to ‘connections and alterations’.[24] More information on this aspect of the UR’s proposals is provided in Appendix 5.1.

NIE’s submissions

5.290 Some of the criticisms that NIE made about the UR’s proposed Fund 2 arrangements applied to the UR’s proposals in relation to connections.[25] In particular, NIE was concerned about the potential for the UR to disallow expenditure that the UR considered inefficient, and about the role of the reporter. NIE proposed a ‘traditional’ approach under which the costs that the UR identified for Fund 2, including connections costs, would be part of an ex-ante allowance without the adjustments for identified inefficiency or differences between actual and forecast volumes.

Our assessment

5.291 We first deal with the issue of the inefficient spend clause. We have considered an inefficient spend clause in section D2. We recognize that such a clause, combined with the UR’s proposals for an embedded reporter, might expose NIE to substantial risk of not recovering expenditure that it considers was efficient but which the reporter or the UR considers inefficient. The risk to NIE would depend on the nature and drafting of the clause. We suggest that, if such a clause is to be included as part of price control design, NIE’s financial exposure should be limited to instances where its expenditure is demonstrably inefficient or wasteful. We do not consider that such an approach would impose an unreasonable regulatory risk on NIE.

5.292 We have looked at the costs that the UR proposes to treat on a cost pass-through basis. These comprise two elements:

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[24] UR Final Determination, p46.
[25] ibid, p55.

(a) Some costs which are effectively a contribution from NIE's maximum regulated revenue and RAB towards the charges for new connections. The charges to consumers for new connections (also known as customer contributions) are subject to price regulation outside the NIE revenue control that is the main subject of our inquiry. The UR's proposals would limit NIE's recovery of these costs to costs incurred in the period to October 2014.

(b) More than half the costs proposed by the UR for full cost pass-through under the connections element of the UR's Fund 2 proposals did not relate to the costs of new connections. Instead these costs relate to necessary alterations that are not funded from upfront connection charges.

5.293 Cost pass-through of the costs under *(a)* does not seem unreasonable on the basis that the final connection charges are regulated through other means. There is a risk of pass-through of excessive costs, but that comes from the risk that the regulation of connection charges in general is not effective. If that is the case, the appropriate solution would be an improvement to the regulation of connection charges rather than a departure from the UR's cost pass-through proposals. The cost pass-through of the costs under *(a)* would be a temporary arrangement as the 'subsidy' from the RAB has been terminated.

5.294 We propose a cut-off date for the cost pass-through arrangement of 1 October 2014. Any costs incurred after this date would not be recoverable through NIE's RAB. This cut-off date is in line with the UR's proposals and its policy decisions in relation to the connections subsidy (see Section 9 for further information).

5.295 We have not identified any good basis to include the alteration costs falling under *(b)* above as part of the cost pass-through arrangement. We propose instead that these are treated as for other elements of NIE’s expenditure with an upfront regulatory forecast and subject to the general cost risk-sharing mechanism.

5.296 The UR told us that it agreed with our proposal to exclude these alteration costs from the pass-through arrangement. NIE told us that it had no objection provided that we determined an adequate upfront allowance.

5.297 It would be important that cost reporting arrangements are in place to ensure that only the ‘subsidy’ that is provided through the revenue control and RAB for portions of the connection charges that NIE levies on parties requiring new connections is treated as a pass-through expenditure.

D9: Pass-through of some operating costs and treatment of injurious affection

5.298 In the current price control, some of the operating costs that NIE incurs are passed through, in full, to consumers. These relate to: the regulatory Licence fees that NIE pays; wayleaves; and network and business rates (forms of taxation on NIE’s premises and assets). These costs were £87 million in the RP4 price control period in 2009/10 prices.[26]

5.299 In its draft determination, the UR proposed that NIE should have some financial exposure to rates and wayleave costs. In its final determinations, following arguments from NIE that such costs were uncontrollable, the UR proposed that rates and wayleave costs should be treated as pass-through costs for the RP5 price control period.

5.300 In addition, NIE identified possible costs associated with legal claims for injurious affection which it considered were so unpredictable as to be unsuitable for ex-ante

[26] UR draft determination, paragraph 7.12.

regulation. Claims of injurious affection concerned diminution in value to a property caused by the existence or use of public works carried out under or in the shadow of compulsory powers.[27] NIE is currently in receipt of claims for injurious affection and the Lands Tribunal of Northern Ireland is considering a number of these claims.[28] NIE said that it was content with the proposal from the UR's draft and final determinations to wait until the outcome of the Lands Tribunal cases before considering how to treat the associated costs.

5.301 In its initial submissions to the CC, the UR asked that we reconsider whether NIE should have some financial exposure to the costs relating to rates, wayleaves and injurious affection.

UR and NIE's submissions on rates

5.302 There has been some confusion over the course of the inquiry on the nature of the rates that NIE pays and which are currently the subject of a cost pass-through arrangement. The UR had originally drawn a distinction between rates that NIE pays in respect of its network, under the Valuation (Electricity) Order (Northern Ireland) 2003, and other rates it pays in relation to its other buildings. We have established that the latter are very small and our consideration of potential cost pass-through arrangements is limited to the former, which NIE has referred to as the cumulo assessment.

5.303 NIE has clarified as follows:

> NIE's uncontrollable cost forecast in respect of rates relates entirely to the cumulo assessment which is based on transmission circuit length

[27] ibid, p176.
[28] ibid, p176.

and MVA transformer capacity. The specific properties occupied by NIE do not form part of the cumulo formula.

Apart from the cumulo assessment, the only rates payable are in respect of a property which is rented by NIE Powerteam at Fortwilliam in Belfast. The annual rates payable in respect of this property (approx. £40k per annum) are accounted for as part of NIE Powerteam's indirect costs; the cost is not included in the uncontrollable rates forecast which relates solely to the cumulo assessment.

Except as described above, NIE does not pay rates on its buildings and offices.

5.304 NIE argued that its rates were fixed by a statutory formula over which it had no control and, for that reason, it was appropriate that these costs were funded on a pass-through basis.[29]

5.305 The UR provided a refined position in light of NIE's clarifications:

NIE T&D are and will continue to be rated under the prescriptive Valuation (Electricity) Order (Northern Ireland) 2003 until 1st April 2015 (http://www.legislation.gov.uk/nisr/2003/77/made). From 1st April 2015 this prescriptive (hard coded formulae driven) statutory rule will be repealed and replaced with a new method based on a more conventional (current GB) valuation model. GB moved away from a formula driven prescriptive method in 2005. A rating review was planned for Northern Ireland in 2010, to bring us into line with the GB practice. Nonetheless it was postponed due to the view that the economic conditions at the time were too delicate.

[29] NIE supplementary submission, p86.

However, NIE T&D will be meeting with the NI Land and Property Services (LPS) over the next few months to kick off the process of a ratings review. This review will result in implementing a new revised conventional (GB) valuation model that is set to take effect from the 1st April 2015. It is the aim of the LPS (where possible) to try and harmonise the ratings valuation calculation methods in Northern Ireland with those in GB with regard to utility companies rates.

One important point is; under the current prescriptive valuation order NIE T&D have no right of appeal, but under the revised conventional valuation model from 2015, they will have the right to challenge and appeal the valuation. First with the Land and Property Services Commission Valuator and then beyond that with the Northern Ireland Lands Tribunal.

While there are a number of buildings that are 'excepted' and thus valued separately, we agree with NIE T&Ds assessment that the ‘cumulo assessment’ set out in the current valuation order will continue to be in place up to 2015 which is calculated based on the Transmission Circuit Length and MVA Transformer capacity and these factors are driven by network demand. However, following April 2015 these costs cannot be deemed as uncontrollable as NIE T&D will have some influence and right of appeal under the newly revised conventional valuation model.

UR and NIE’s submissions on wayleaves

5.306 In its initial submissions to the CC, the UR said the following in respect of wayleaves:

> These are payments that NIE T&D is required to make to landowners in respect of equipment that NIE T&D owns on their land. Unlike the position with respect to rates, there are no regulations that stipulate the

amount to which landowners are entitled. Rather, those sums fall to be negotiated between the landowners (or their collective representatives) and NIE T&D. NIE T&D contends that they are uncontrollable because it treats the payments made by Scottish Power as a precedent for its negotiations. But that is just the choice that NIE T&D has made (no doubt reflecting the fact that it has no incentive to reduce costs in this area), rather than evidence that it does not have a choice. We note that Ofgem treats wayleaves as controllable, and consider that this is a matter that would benefit from the Commission's detailed appraisal.

5.307 NIE made the following claims:[30]

> NIE's current processes for paying wayleaves is efficient and UR's proposal that NIE might negotiate lower wayleave rates in NI would significantly increase the cost of administration and it is extremely unlikely that lower rates could be agreed.
>
> Wayleaves are therefore an uncontrollable cost and should be treated as a pass-through.

5.308 NIE explained that it did not negotiate wayleave payments on a case-by-case basis with individual landowners. Rather, its rates were based on ScottishPower's way-leave rates which were in line with the rates recommended by the Electricity Networks Association (ENA) which acted on behalf of the UK electricity network companies. NIE said that its approach had significant benefits in ensuring that land-owners and their representatives were satisfied that the payment being made by NIE was fair and non-discriminatory and that any challenge to those rates was unlikely to be successful. NIE considered its current approach efficient in light of administrative costs.

[30] NIE supplementary submission, p87.

UR and NIE's submissions on injurious affection

5.309 In its draft determination, the UR proposed the following in relation to costs associated with injurious affection:[31]

> NIE T&D included £11.4 million for injurious affection costs under uncontrollable opex. Injurious affection is 'the diminution in value to a property caused by the existence and/or use of public works carried out under, or in the shadow of compulsory powers'.
>
> NIE T&D believes that the number of claims and the trend towards significant settlements will have a similar impact as it has on the GB DNOs. However, to date this has not been NIE T&D's experience.
>
> We are therefore minded to treat this as an uncertain cost. However we cannot agree to an allowance proposed as there are no historical costs on which to determine a suitable baseline. We will therefore wait for the results of the Lands Tribunal before considering how to treat these costs.

5.310 In its initial submission, the UR proposed that we reconsider the treatment of costs associated with injurious affection:[32]

> Injurious affection: These are damages that NIE T&D anticipates needing to pay as a result of litigation (or potential litigation) from landowners in respect of any diminution in the value of their property caused by the existence or use of public works carried out under, or in the shadow of, compulsory powers. So far no such claims against NIE T&D have proceeded to judgment. There is therefore naturally a significant degree of uncertainty as to the costs associated with these claims, and they are, to some extent, out of NIE T&D's control.

[31] UR draft determination, p107.
[32] UR Statement of Case, UR-2, p9.

> However, as with all litigation which is capable of settlement, NIE T&D must have some control over the outcome and we note that Ofgem treats such costs as controllable and consider that this is, again, a matter that would benefit from the Commission's detailed appraisal.

5.311 NIE said that it was content with the UR's (previous) proposed approach of awaiting the results from the Lands Tribunal before considering how to treat these costs and elaborated as follows:[33]

> NIE is currently in receipt of a number of claims for injurious affection and the Lands Tribunal of Northern Ireland is currently considering the legal and valuation issues associated with a number of these claims. The outcome of this process is uncertain. While precedent exists in GB, there is no precedent for the payment of such claims in Northern Ireland.
>
> It follows that the costs associated with injurious affection that NIE will incur in the next few years are so unpredictable as to be unsuitable for ex ante regulation. A different approach may be possible in later regulatory periods once the scale of these costs becomes known.

Third party submissions on pass-through of operating costs

5.312 Some third parties made submissions in relation to the cost items proposed in this section that provide further context.

5.313 The Ulster Farmers' Union (UFU) said that contrary to the UR's position, rates and wayleaves were not semi-controllable.[34] The UFU continued that it was concerned with the UR's proposals that the level of wayleave costs during the RP4 price control

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[33] NIE Statement of Case, p176.
[34] UFU submission, 31 May 2013.

period was used as a baseline for an RP5 allowance. The UFU said that it feared this approach could mean a reduction in the wayleave payments to local landowners which it considered should be wholly unacceptable. The UFU felt that wayleave rates should be rising as new equipment was brought into its members' land during RP5.

5.314 In its submission to the CC, Bombardier Aerospace urged careful consideration on the treatment of uncontrollable opex and how consumers were protected if there was cost pass-through.

Ofgem approach to wayleaves, rates and injurious affection

5.315 In 2009, Ofgem set price controls for electricity distribution companies for a five-year period from April 2010. For this price control, Ofgem did not treat wayleave costs or injurious affection costs as cost pass-through items. Instead it included these costs in its ex-ante allowance, and the GB DNOs are exposed financially to these costs.

5.316 Ofgem is currently carrying out a price control review for electricity distribution companies (RIIO ED1), intended to apply from April 2015. In March 2013 it published a decision on its strategy for the price control. Ofgem plans to include costs relating to wayleaves and injurious affection as part of the ex-ante allowance.[35]

5.317 Ofgem's approach for RIIO ED, Ofgem's March 2013 strategy decision, said the following in relation to business rates:[36]

> Our decision on business rates is to introduce the same incentivisation approach to business rates as applied to transmission and gas distribution licensees. This effectively retains business rates as a pass through from the next revaluation due in 2017, subject to DNOs demonstrating that they have taken appropriate actions to minimise the valuations. As

[35] Strategy decision for the RIIO-ED1 electricity distribution price control: tools for cost assessment', p32.
[36] 'Strategy decision for the RIIO-ED1 electricity distribution price control: uncertainty mechanisms', p34.

a result of our decision of October 2012 to introduce measures to mitigate charging volatility, this mechanism will operate with a lag. In practice this will mean that an allowance is provided based on the expected value of the pass through cost for the eight years of the price control. The mechanism will adjust this ex ante allowance to true up for actual costs incurred, but with a two year lag. The true-up will take account of financing costs from the delay in recovery of actual costs incurred.

Our assessment: approach to the questions at hand

5.318 The UR's approach to whether certain operating costs are to be subject to full cost pass-through turns on a view as to whether they are 'controllable' or 'uncontrollable'. The concept of 'uncontrollable' costs is reflected in the drafting of the current Licence conditions, which refer to 'uncontrollable operating costs'.

5.319 We do not consider that decisions on whether certain operating costs should be subject to full cost pass-through should rest on an assessment of whether the costs are 'controllable' or 'uncontrollable' or even 'semi-controllable'. Factors that affect the extent to which NIE can influence certain operating costs are relevant to decisions on whether to apply cost pass-through. As we highlight below, these not the only relevant considerations.

5.320 Furthermore, the concept of 'uncontrollable' costs is not straightforward to apply. NIE has some influence over all the costs under consideration. This should be obvious for costs such as those relating to injurious affection, where NIE will need to make decisions relating to the potential settlement of legal claims. But it is also true for other items that have been described as uncontrollable.

5.321 An attempt to draw a firm distinction between controllable and uncontrollable seems to be a distraction from what matters most for price control purposes. Decisions are needed on the design of the price control. We have options that include the following in relation to the operating costs considered in this section:

(a) Treat these costs in the same way as the remainder of NIE's opex, in which an upfront forecast of NIE's efficient expenditure requirements is made and NIE is subject to a cost risk-sharing mechanism in relation to overspends and underspends against the forecast. Under this approach, NIE would be financially exposed to these costs. A downside of this approach is the time and resource required by the regulator (or us) to determine a reasonable forecast of these costs. Another downside is the potential that the forecast is too high or too low.

(b) Treat these costs on a full pass-through basis. This approach does not suffer from the forecasting risk that arises under *(a)*. But there is a risk of exposing consumers to unnecessarily high costs if NIE has some influence over its costs and yet faces no financial incentive to reduce or restrain them. There is also a risk of distorting NIE's working practices if it faces choices which affect the extent which the costs it incurs fall under the category of costs subject to full cost pass-through. For cost pass-through to be practical, it is necessary that the costs subject to pass-through can be separately identified and reported.

5.322 These are not the only plausible options. For each cost item, it may be possible to develop an alternative to the options above that provides some protection to consumers and NIE against the uncertainty in forecasting costs under approach *(a)* above but which does not completely remove NIE's financial exposure to the costs it incurs. Ofgem refers to such arrangements as 'uncertainty mechanisms'.

5.323 Factors which underpin views about the extent to which costs are 'controllable' by NIE will be relevant to the risks under the pass-through approach *(b)* above. But that is not the only consideration. For instance, the time and effort to get a reasonable expenditure forecast, and the scale of the cost item, is relevant to decisions about whether to use approach *(a)* or something else.

Our assessment: Licence fees

5.324 Both parties proposed that Licence fees be treated as a cost pass-through item. This approach seems reasonable. Indeed, the UR has more influence on the level of Licence fees than NIE and it is no bad thing if the UR appreciates that the level of these will feed into consumer charges.

Our assessment: rates

5.325 NIE forecast rates of more than £12 million per year from April 2012 (2009/10 prices, source: NIE BPQ).[37] This is a large amount of money in the context of the price control review.

5.326 The Northern Ireland Finance Minister has announced that a Northern Ireland ratings revaluation will take place in April 2015 and said that the outcome of this revaluation was unknown. We would expect NIE to have some opportunity to make representations as part of the revaluation process and even to make use of appeal procedures if it was concerned that the revaluation was unfair.

5.327 We propose that NIE's rates are not subject to the cost pass-through mechanism. We consider it important to ensure that NIE is not financially indifferent to the outcome of the anticipated Northern Ireland ratings revaluation.

[37] Section 10 provides forecasts of NIE's rates.

5.328 We do not consider that uncertainty about the outcome of the potential Northern Ireland ratings revaluation is sufficient to mean that it would be inappropriate for NIE or consumers to face financial risk around a regulatory forecast of NIE's rates liability.

Our assessment: wayleaves

5.329 Ofgem does not treat wayleaves as a cost pass-through item.

5.330 The indirect cost benchmarking analysis put to us by both NIE and the UR use measures of NIE's costs that include NIE's wayleave payments. This seems to have been done to ensure a like-for-like comparison between NIE and GB DNOs. It would be practical to include wayleaves in the group of costs subject to the approach applied for other elements of NIE's opex which uses data on NIE's historical expenditure and results from benchmarking analysis to produce an approximate estimate of NIE's future expenditure requirement. Doing this would bring greater consistency between the set of costs covered by the benchmarking analysis and the set of costs to which the results of that analysis are applied.

5.331 The submission to the inquiry from the UFU suggests that NIE can have a significant influence on the level of wayleave payments to landowners.

5.332 Whilst NIE asserted that its approach to wayleaves was efficient, its submission also revealed that it had potentially difficult trade-offs to make between the costs of wayleave payments to landowners, administrative costs of its wayleave payment process and the benefits of landowners' goodwill.

5.333 We propose not to treat costs associated with wayleaves as a pass-through item. Instead, we will include an allowance for wayleaves in light of our analysis of indirect costs, drawing on benchmarking analysis covering NIE and GB DNOs.

5.334 NIE told us that it wanted to emphasize that departing from its current practice of basing wayleave rates on ScottishPower's wayleave rates was likely to lead to an increase in both the costs of wayleaves and the costs of administration. We express no view on whether NIE should make such a change of practice. This will be for NIE to decide.

Our assessment: injurious affection

5.335 In its draft determinations, the UR proposed an approach under which it would wait for the results of the Lands Tribunal before considering how to treat costs associated with injurious affection. NIE endorsed this approach. In its initial submissions to the CC, the UR suggested that we reconsider the appropriate approach.

5.336 The UR described its proposed approach in its draft determinations as one in which costs associated with injurious affection would be treated 'as an uncertain cost' and proposed that it would 'wait for the results of the Lands Tribunal before considering how to treat these costs'. The UR provided no further information in its draft and final determinations on what this would mean in practice or what its approach might be following the results of the Lands Tribunal. However, under the draft Licence modifications that the UR published alongside its final determinations, the proposal was that 'amounts incurred by the Licensee in respect of injurious affection' would be subject to full cost pass-through.[38]

5.337 If the draft Licence conditions proposed by the UR were implemented, NIE would be entitled to full cost pass-through of costs incurred in respect of injurious affection. The UR might seek to amend the treatment of these costs, following the results of the Lands Tribunal, through subsequent Licence modification. But Licence modification currently requires NIE's consent. NIE would be able to block any change in treatment

[38] UR Draft Licence Modifications, Clause 4.4.

which it does not consider preferable to full cost pass-through. Whilst the UR could refer the matter to the CC, the UR might consider the treatment of injurious affection to be insufficiently important on its own to justify a reference. We suspect that, under the draft Licence modifications proposed by the UR, the UR would be in a weak position to implement an alternative to cost pass-through following the Lands Tribunal decisions, unless it made the terms of such an arrangement sufficiently attractive to NIE for NIE to accept the higher financial risk that would come from a move away from full cost pass-through.

5.338 There are risks of distorting NIE's expenditure decisions if it faces no financial exposure to costs associated with injurious affection but is exposed financially to the costs of other decisions which affect the former (eg potential network diversions). In its RIIO ED1 strategy decision consultation paper on tools for cost assessment,[39] Ofgem said that, in relation to the options it was considering for the treatment of claims of injurious affection, it was important that the relative costs of settling a claim versus triggering a diversion were also considered. If NIE faced financial exposure in relation to network diversions but was fully insulated from the costs it incurs settling claims, it may favour the latter even if the former would bring the lowest overall cost.

5.339 There is a further risk that if injurious affection is a cost pass-through in the next price control period, but NIE expects it to face some financial exposure to these costs in the future (in line with the UR's suggestions and Ofgem policy), it may face financial incentives to settle as many claims as possible in the period whilst cost pass-through applies. This could expose consumers to unnecessarily high costs.

[39] Ofgem RIIO-ED1 Strategy consultation paper: tools for cost assessment, September 2012, p32.

5.340 Against these concerns of inefficiency, the costs that NIE needs to incur in relation to injurious affection, and the timing of these costs, is difficult to predict. There is a risk for consumers, for example, from setting an upfront forecast that is too high.

5.341 We identified four approaches:

(a) full cost pass-though, as proposed in the UR's draft Licence conditions;

(b) no allowance for injurious affection within the price control, but a provision for the UR to amend the revenue control on NIE to include an upfront allowance once the results from the Lands Tribunal are known and NIE's costs can be forecast with more confidence;

(c) make a forecast based on any available data on the costs incurred in relation to injurious affection by GB DNOs; and

(d) make a forecast as under *(c)* but specify that this only comes into effect as an allowance for NIE once the results from the Lands Tribunal are known (this rests on this trigger point being defined).

5.342 The UR expressed a preference for *(b)*. The UR considered options *(c)* and *(d)* too risky given the uncertainty as to the outcomes of the Lands Tribunal ruling. In relation to the approach under *(c)*, the UR identified some issues that arose in seeking to use data from other DNOs. The UR told us that the relevant costs related to land value which varied between locations and it would be concerned about setting an allowance for NIE that was higher than necessary. The UR also expected that many of the more significant costs for NIE would relate to its 275 kV network whereas GB DNOs did not operate at 275 kV.

5.343 NIE told us that it saw difficulties with each approach apart from full cost pass-though under *(a)*. NIE said that option *(b)* would provide no effective legal recourse in the event that the UR failed to determine an appropriate upfront allowance once the results of the Lands Tribunal were known. NIE said that option *(b)* would expose it to an unacceptable degree of regulatory risk. In relation to option *(c)*, NIE said that it would not be possible for the CC to produce a meaningful forecast of NIE's costs in relation to injurious affection by reference to the costs incurred by GB DNOs. NIE said that option *(d)* rested on the feasibility of *(c)* so the concerns in relation to *(c)* applied; NIE also said that specification of a trigger point would be difficult.

5.344 We have strong reservations about an arrangement in which NIE can pass through any costs it incurs in relation to legal claims (whether valid or not) directly to consumers and in which NIE would face no financial exposure to the action it takes in this area. This is especially so if, as noted above, NIE expects cost pass-through to be a temporary arrangement after which it may be exposed financially: NIE might rush to settle claims that it would not otherwise pay so as to maximize the benefits it receives from the cost pass-through arrangement.

5.345 We propose option *(b)* above: there would be no upfront allowance for costs relating to injurious affection but a provision for the UR to make an allowance in the future following the Lands Tribunal determination. In the absence of other data sources, we would expect the UR to give weight to data from GB DNOs but also to take account of any differences between the Lands Tribunal determination and relevant precedent from GB.

5.346 We accept that NIE faces some regulatory risk under this option, but do not consider it unreasonable. Whilst the scale of costs is unknown, the order of magnitude is likely to be small in relation to NIE's business. NIE's BPQ response on opex provided forecasts of around £170,000 per year; we appreciate that there is substantial uncertainty but this does give an indication of potential scale.

Implementation of pass-through mechanism

5.347 NIE raised a concern with the draft Licence modifications proposed by the UR to implement a cost pass-through mechanism for specified operating costs. The UR's proposed mechanism would make use of an upfront forecast of the level of the relevant costs, with adjustments made if out-turn costs are higher or lower than this. NIE raised two points:[40]

(a) The upfront forecast of the level of the relevant costs proposed by the UR was lower than NIE's forecast (the difference related to rates and wayleaves).

(b) The proposed Licence modifications contained no mechanism for the recovery of any shortfall in costs against the forecast in the last year.

5.348 NIE said that both problems could be overcome by defining the relevant costs as pass-through costs without specifying ex-ante value, which NIE said was the approach under the current Licence conditions. The impact of NIE's approach was that NIE would need to make its own forecast of these costs for the purposes of calculating its maximum regulated revenue in a particular financial year and would subsequently need to deal with any difference between its forecast and out-turn costs through an adjustment through the corrector factor (KD_t), in the current Licence.

5.349 We propose to accept NIE's proposed approach to implementation. Nonetheless for the purposes of forecasting the impact on our proposals on prices, we make fore-casts of costs subject to pass-through.

D10: Other terms to remove from current Licence conditions

5.350 To implement the price control design set out above would require a series of changes to NIE's Licence conditions. There may be elements of the existing Licence conditions that should not be maintained.

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[40] NIE Statement of Case, p112.

5.351 We identified the following elements as potentially redundant:

(a) the Powerteam profit-sharing term (PPS_t);

(b) the revenue cap implemented through the PC_t term (and the related RRF_t term); and

(c) provision (viii) under D_t term.

5.352 The UR told us that it agreed that the elements above were redundant.

5.353 The redundancy of the Powerteam profit-sharing term arises from our view that the costs reported for NIE which may affect the calculation of NIE's maximum regulated revenue or RAB should not include any Powerteam profit. Rather than seeking to share Powerteam's profit between consumers and NIE's investors, we propose that the price control is set in a way that does not expose consumers to any Powerteam profit.

5.354 The revenue cap implemented through the PC_t term is an element of the current price control Licence conditions which the parties have not drawn attention to in their submissions to us. For example, its existence is not highlighted in NIE's description of the RP4 price control.[41] This term seems to be treated by the parties as redundant. Neither of the parties has made a case for maintaining it. We have not identified a good reason to do so.

5.355 Provision (viii) under the D_t term provides for the maximum regulated revenue to be adjusted to allow for additional costs approved by the UR. This term has been used by the UR on several occasions to increase NIE's maximum regulated revenue during the RP4 price control period. It may no longer be necessary or appropriate. The following points seem relevant in this regard:

[41] ibid, pp402–403.

(a) The current Licence conditions already include a change of law provision which allow maximum regulated revenue to be adjusted by the UR in cases of change of law. We do not propose the removal of the change of law provision (COL_t) and propose Licence modifications to ensure that it continues to apply.

(b) We have considered above the potential to allow flexibility within the price control for the UR to approve adjustments to maximum regulated revenue and RAB in light of the expenditure requirements that arise in relation to specified activities (eg investment in transmission system capacity).

(c) The cost risk-sharing mechanism described earlier in this section provides some financial protection against unexpected cost increases.

(d) If both NIE and the UR believe that the price control should be adjusted to provide NIE with more money, they could agree Licence modifications to this effect. This process might involve higher administrative costs than approval for additional funding under the D_t term, but also has potential benefits in terms of transparency and accountability.

5.356 NIE told us that it had no objection to the change in relation to the Powerteam profit-sharing term and the revenue cap implemented through the PC_t term, but that the position with regard to the D_t term was more complicated. NIE said that if the 'catch all' D_t term was removed, a series of specific further elements were needed:

(a) The recovery of costs effectively promised to NIE under previous regulatory decisions. NIE identified costs relating to: SONI deficit repair; specific network management system costs in the period to December 2013 that have been approved by the UR; costs in relation to the North–South interconnector in the period to December 2013 that have been approved by the UR; the costs of specific renewable projects approved by the UR for the period to December 2013; the residual of the smart grid trial costs approved by the UR; and capex efficiency payments.

(b) Additional costs that NIE might incur in relation to Enduring Solution.

(c) A mechanism to allow recovery of costs associated with exceptional weather events that cost NIE more than £1 million. NIE proposed that it received additional revenue, in such cases, to cover its costs.

(d) A mechanism to allow NIE to recover bad debt from other customers.

5.357 In light of the above, we propose that the Licence modifications proposed to remove provision (viii) of the D_t term are accompanied with:

(a) a provision to allow NIE recovery of the specific costs approved under previous regulatory decisions by the UR, as specified in paragraph 5.357*(a)*;

(b) a provision for the UR to make an adjustment to NIE's price control for significant changes in the specification of the service that NIE is required to provide in relation to market systems and the Enduring Solution (such adjustments should be subject to consultation and published documentation); and

(c) a mechanism to ensure that NIE can recover bad debt from other customers. This seems compatible with the notion of an aggregate revenue control with adjustments for over- and under-recovery.

5.358 We are not persuaded by NIE's proposals that the price control is reopened in cases of storms that cost more than £1 million. NIE has not established the need for such a mechanism. We have included an expenditure allowance for atypical weather events as part of our cost assessment in Section 10.

6. Regulation of quality of service

Introduction and summary

6.1 In Section 5 we considered the design of a new price control for NIE, in light of our finding of the ways in which the current price control licence conditions operate against the public interest. This section considers a number of further aspects of price control design which concern the regulation of NIE's quality of service and the price control treatment of NIE's revenue protection activities. We take the following issues in turn:

(a) guaranteed standards;

(b) customer interruptions incentive scheme;

(c) electrical losses incentive scheme; and

(d) revenue protection and illegal abstraction of electricity.

6.2 Appendix 6.1 provides further information on the parties' submissions on these issues, some related matters and our assessment of them.

Guaranteed standards

6.3 NIE is currently required to meet a series of standards concerning aspects of its service to consumers. These standards are specified in a determination that UR made under Article 43 of the Electricity (NI) Order 1992 and in Regulations made under Article 42 of the same Order.

6.4 Some of the standards give customers experiencing shortfalls against standards a right to specified amounts of compensation. For instance, according to Table 13.3 of the UR's draft determination, if NIE takes more than 24 hours to restore electricity to a domestic consumer following a fault, it must pay the consumer £50, and an additional £25 for every 12 hours that the electricity stays off after the first 24 hours.

6.5 The specification or implementation of guaranteed standards are not the subject of our inquiry since they are not part of the price control licence conditions referred to us. While NIE has concerns about the UR’s interpretation of the current standards and about potential future changes to the standards, we do not consider that these are matters that we should seek to resolve.

Customer interruptions incentive scheme

6.6 The price controls for GB electricity distribution companies include a financial incentive scheme concerning the number and duration of interruptions to customers’ electricity supplies. Both NIE and the UR have proposed the introduction of such a scheme in Northern Ireland.

6.7 The introduction of a well-designed interruptions incentive scheme for NIE would be reasonable. However, the specification of an interruptions incentive scheme is a complex matter: a poorly designed scheme could be worse than no scheme and could impose unnecessary costs on consumers. The parties dispute several important aspects of the design and calibration of such a scheme.

6.8 We have not found that the absence of such a financial incentive scheme operates against the public interest and therefore we have not included the introduction of such a scheme in our provisional determinations.

6.9 Instead, we propose that NIE publishes its annual performance in terms of measures of CMI and CML. We also propose that NIE publishes a forecast of its performance in terms of these measures over the period to 30 September 2017, in light of its recent and planned network investment, and explains any shortfalls in performance against its forecasts.

Electrical losses incentive scheme

6.10 In its RP5 proposals, the UR set out its ambition to introduce a financial incentive scheme for NIE concerning the volume of electrical losses on its network. The UR did not include a losses incentive scheme in its RP5 proposals but envisaged introducing such a scheme during the RP5 period following work to resolve data issues.

6.11 Ofgem has withdrawn the electricity distribution losses incentive scheme that previously applied to distribution companies in GB; that scheme had not worked as intended.

6.12 Neither NIE nor the UR proposed that we should introduce an incentive scheme for electrical losses as part of our inquiry, though both were keen that we did not suggest that it would be inappropriate for such a scheme to be introduced in the future.

6.13 NIE has a statutory duty to 'develop and maintain an efficient, co-ordinated and economical system of electricity distribution'.[1] We have not found that the absence of a specific financial incentive scheme for electrical losses from NIE's price control licence conditions operates against the public interest.

6.14 We have not included the introduction of a losses incentive scheme in our proposals.

Revenue protection and illegal abstraction of electricity

6.15 The illegal abstraction of electricity from NIE's electricity system indirectly imposes costs on other electricity consumers who are consuming lawfully. The act of consuming electricity illegally does not directly impose a cost on NIE because NIE is not exposed financially to any losses of electricity on its network.

[1] Article 12 of the Electricity (Northern Ireland) Order 1992.

6.16 The term ‘revenue protection’ is used in the electricity industry to describe activities to detect and deter cases of illegal abstraction of electricity (and electricity theft) and to collect money owed in relation to that illegal abstraction.

6.17 NIE has certain powers to recover money in cases of illegal abstraction of electricity. In 2009/10, NIE received around £425,000 in revenue arising from its revenue protection activities. NIE also incurs costs investigating and dealing with instances of illegal abstraction.

6.18 We have considered how the income that NIE earns from revenue protection activities should be treated as part of the new price control. We propose that 50 per cent of the income that NIE receives each year in relation to revenue protection activities (including money recovered by NIE from parties who have engaged in illegal abstraction of electricity) should be used to offset NIE’s maximum regulated revenue in the financial year two years later. The two-year delay allows time for the preparation of accounting information on revenue protection income and for the calculation of the impact on NIE’s revenue restriction before tariffs need to be set. For the purposes of that calculation, we propose to use the same interest rate or discount rate as used for the correction factor in the current licence conditions (K_{Dt} term).

6.19 We have sought to ensure that NIE can benefit financially from its efforts to recover money in cases of illegal abstraction of electricity whilst also ensuring that consumers benefit from the money recovered; this can help offset the costs to consumers from illegal abstraction.

6.20 The value of 50 per cent reflects the current scheme reported by NIE and the UR for vacant non-domestic premises that the UR proposed to retain. However, our proposal would apply not only to revenue from cases of vacant non-domestic premises but also revenue that NIE has collected in other circumstances of illegal abstraction. We have not identified a good basis for differing treatment between vacant non-domestic premises and other premises and we see merit in limiting the complexity of the price control licence conditions.

7. Overview of cost assessment and provisional determination

7.1 We need to determine appropriate figures for NIE's opex and capex that can be used as part of the calculation of a new price control for NIE. Our aim is to estimate the expenditure that NIE would incur if it operated and invested efficiently, given the services (and outputs) it will provide and the obligations that it will face. Our detailed cost assessment analysis is provided in Sections 8 to 11.

7.2 This section provides an overview of several elements of our approach to cost assessment. It gives particular attention to the steps we have taken to ensure that we make best use of the information available on the costs of electricity network companies in GB, which allows benchmarking analysis to be carried out for parts of our cost assessment work. It is structured as follows:

(a) we recap the period over which we will make our cost assessment;

(b) we explain the role of benchmarking in our cost assessment;

(c) we consider the alignment of our cost assessment with the cost categories which are used by Ofgem;

(d) we explain how our work on cost assessment has been structured;

(e) we explain how we have adjusted our cost assessment for real price effects (RPEs) and productivity;

(f) we present an overview of the results of our detailed cost assessment;

(g) we provide an overview of additional items of expenditure which are not covered in our cost assessment; and

(h) we consider the potential additional transmission expenditure which could result from our price control design.

Time period over which we make a cost assessment

7.3 Section 4 discussed issues relating to the timing of a new price control for NIE. In light of the approach set out in that section, our cost assessment needs to cover the following two periods:

(a) The period over which our new price control is intended to determine the calculation of NIE's tariffs, which we propose is 1 October 2014 to 30 September 2017. We explain in Section 4 that the earliest practical date for our price control to affect tariffs is 1 October 2014. An end date of 30 September 2017 is consistent with the UR's Final Determination and has not been disputed by either of the parties.

(b) The period from 1 April 2012 to 30 September 2014. As we explain in Section 4, we propose to make financial adjustments as part of the calculation of the revenue control in the period under *(a)* above in light of differences between NIE's actual revenue in the period 1 April 2012 to 30 September 2014 and our assessment of the revenue it 'ought' to recover in respect of that period. These financial adjustments are intended to compensate consumers if we think that NIE has collected too much revenue in the period since the anticipated end of the RP4 price control and 1 October 2014; or to compensate NIE if we think that it has collected too little revenue in that period.

7.4 The combined effect is that we make our cost assessment over the 5.5-year period from 1 April 2012 to 30 September 2017. In our work on cost assessment, we tend to use the term price control period to refer to the 5.5-year period which our assessment covers.

Role of benchmarking in cost assessment

7.5 There is considerable merit in using benchmarking analysis as part of our price control determination, as this can provide information on the costs that NIE might efficiently incur (see paragraph 7.1). In particular, benchmarking analysis can help reduce reliance on the use of data on NIE's historical costs in setting a new price control for NIE. This has several benefits in the context of RAB-based incentive regulation:

(a) If an allowance for NIE's costs were based purely on an extrapolation of its historical costs, this would expose consumers to any inefficiency reflected in NIE's past costs.

(b) If NIE expects that its price control allowances for certain categories of expenditure (eg opex) will be based on its past spend in those areas, this may provide it with little financial incentive to achieve efficiency improvements and restrain its costs. Reductions to NIE's costs would be expected to lead mechanistically to lower revenue allowances in the future. In contrast, setting price controls by reference to the costs of other electricity network companies reduces the extent to which NIE's revenues and profits would depend on its own costs—whilst still using historical information on electricity network costs. This can help provide NIE with financial incentives to achieve efficiency improvements and avoid unnecessary expenditure.

(c) Using cost information from a range of other companies can help reduce the exposure of price control calculations to any data anomalies that may be reflected in the reported costs for NIE.

7.6 Appendix 7.1 provides further discussion of the points above.

7.7 We have used comparisons of costs between NIE and the GB DNOs as part of our cost assessment, drawing on and further developing analysis presented by NIE and the UR. As discussed below, we found that the desire to make best use of benchmarking analysis had important implications for the way that we have approached the cost assessment for NIE.

Alignment of cost assessment with Ofgem cost categories

7.8 NIE organized its forecasts and submissions on its expenditure requirements between the categories of opex and capex. Similarly, the UR's Final Determination involved separate cost assessment for opex and capex.

7.9 We have not organized our cost assessment using a firm boundary between opex and capex. This is for several related reasons:

(a) The information available to us, particularly that resulting from benchmarking analysis comparing the costs of NIE to the GB DNOs, is not conducive to drawing a firm boundary between opex and capex.

(b) Relying on accounting boundaries between capitalized and non-capitalized expenditure for regulatory cost assessment purposes poses risks of double-counting in areas of expenditure that may straddle those boundaries (eg repairs, maintenance and tree-cutting costs). This is particularly so given the potential for NIE's capitalization practices to change over time (see Section 15) and for differences in capitalization practices between NIE and other companies whose costs might be used for benchmarking purposes.

(c) Adopting a different approach to cost assessment between opex and capex risks creating distortions in the financial incentives that NIE faces. Whilst it is not practicable for us to adopt a single comprehensive method cost assessment for all aspects of NIE's costs, a firm distinction between opex and capex in cost assessment analysis may bring unnecessary differences of approach.

7.10 The information available to us reflects the way that Ofgem requires GB electricity distribution companies to report costs and the way that Ofgem itself carries out cost assessment. Ofgem's approach to cost reporting and cost assessment effectively ignores accounting boundaries between capitalized and non-capitalized costs and instead relies on bespoke cost categories or classifications that Ofgem has developed over time for its regulatory purposes. Ofgem's approach reflects, in part, the concerns highlighted under paragraph 7.9*(b)* and *(c)* above. Ofgem's approach involves some high-level classifications between different types of costs and a large number of granular cost categories.

7.11 Ofgem's approach to cost categorization—and particularly the distinction it draws between 'direct' and 'indirect' costs—is of critical importance to our cost assessment work in this inquiry. In their submissions to us, both NIE and the UR relied on benchmarking analysis of NIE's indirect costs against GB DNOs. NIE also sought to support its expenditure forecasts with reference to comparisons of some of its direct costs against those of GB DNOs.

7.12 Ofgem distinguishes between direct and indirect costs as follows:[1] 'Indirect activities are those activities which do not involve physical contact with system assets.'

7.13 Ofgem then explains that it distinguishes between two main categories of indirect costs: 'closely associated indirects' which can be considered closely associated with network investment and operational activities involving physical contact with system assets; and the remainder, which it calls 'Business Support' activities.

7.14 Drawing on its distinction between direct and indirect costs, Ofgem defines five main categories of expenditure: *(a)* network investment: non-load-related expenditure; *(b)* network investment: load-related expenditure; *(c)* network operating costs; *(d)* closely associated indirect costs; and *(e)* business support costs (another category of indirect costs). Table 7.1 provides examples of the subcategories within each of these five categories which help to illustrate what they cover.

[1] Ofgem (2011) Electricity Distribution Price Control Cost and Revenue Reporting – Regulatory Instructions and Guidance: Version 2.

TABLE 7.1 **Cost categories for Ofgem's current electricity distribution price control review**

Ofgem cost category	*Examples of cost subcategories*
Network investment: non-load-related expenditure	• Asset replacement • Operational IT and telecoms • Legal and safety (investment driven by safety requirements) • Quality of supply • Environmental areas (eg losses, oil pollution, SF6 leakage) • Enhanced site security
Network investment: load-related expenditure	• Connections • General reinforcement • Fault level reinforcement
Network operating costs	• Trouble call (resolution of faults) • Inspections and maintenance • Tree cutting
Closely associated indirect costs	• Call centre • Control centre • Engineering management and clerical support (includes wayleaves) • Network design and engineering • Network policy • Operational training (including workforce renewal) • Project management • Small tools, equipment, plant and machinery • Stores • System mapping • Vehicles and transport
Other indirect costs: business support costs	• Human resources and non-operational training • Finance and regulation • CEO and corporate • IT&T including non-operational capex • Property management

Source: Ofgem.

7.15 Ofgem's cost definitions cut across accounting classifications of costs between capitalized expenditure and non-capitalized expenditure (ie opex). Whilst the category of network investment may align with capitalization, the categories of indirect costs and network operating costs will include costs that companies capitalize and costs that companies do not capitalize. By way of illustration, Figure 7.1 shows our estimate of NIE's indirect costs for 2009/10 and an approximate decomposition of this between the elements of indirect costs that NIE capitalized and the elements of indirect costs that are treated as opex.

FIGURE 7.1

Illustration of breakdown of NIE indirect costs between opex and capex

NIE indirect costs 2009/10 (£47.1 million)		
Indirect costs reported under NIE opex including wayleaves (£25.1 million)	NIE capitalized overheads (£8.7 million)	NIE Powerteam indirect costs that are capitalized (£13.3 million)

Source: CC analysis.

7.16 Similarly, the costs falling under Ofgem's category of network operating costs (eg faults and tree cutting) include costs that NIE capitalized and costs that NIE does not capitalize.

7.17 NIE's submissions made extensive use of benchmarking analysis which compared NIE's costs against GB DNOs, based on the Ofgem cost definitions:

(a) NIE submitted a series of reports providing econometric benchmarking analysis to compare NIE's historical indirect costs against the indirect costs of GB DNOs. This analysis covered both categories of indirect costs from the table above: closely associated indirect costs and business support costs.

(b) The econometric benchmarking analysis also included comparisons of the main elements of NIE's 'network operating costs' against the corresponding costs of the GB DNOs. This was presented as an analysis of NIE's 'R&M' costs.

(c) NIE also submitted a report which provided a comparison of the unit costs of a series of standardized types of network investment project between NIE and the average among the DNOs in GB. These comparisons were made for unit costs on a direct cost basis to allow comparison between NIE (ie the unit costs excluded costs that Ofgem would categorize as indirect costs).

7.18 NIE does not currently report its costs according to Ofgem's cost reporting definitions. The benchmarking reports presented by NIE involved analysis to convert NIE's costs to a format that was compatible with the Ofgem cost definitions to allow, as far as possible, like-for-like comparisons with the costs of GB DNOs.

7.19 NIE said that the benchmarking analysis demonstrated that its costs were efficient.

7.20 However, NIE's expenditure forecasts and submissions in relation to cost assessment suffer from two major limitations (leaving aside the details of the methods used for benchmarking):

(a) The benchmarking analysis that NIE provides is based on Ofgem's cost categories (eg indirect costs, network investment direct unit cost). But NIE's expenditure forecasts are not presented in this way: NIE's expenditure forecasts are organized according to a distinction between opex and capex. NIE did not reconcile its expenditure forecasts for the price control period with the Ofgem cost categories that were used for its benchmarking analysis.

(b) The benchmarking analysis that NIE provides in relation to indirect costs and network operating costs involves a comparison of NIE's historical costs (eg in 2009/10) with the corresponding historical costs of GB DNOs. However, NIE's expenditure forecasts for the price control period are not reconciled with its historical costs.

7.21 An effect of *(a)* is that a finding that NIE's costs are efficient in the particular categories of costs subject to benchmarking analysis does not provide assurance on the efficiency or reasonableness of NIE's expenditure forecasts. An effect of *(b)* is that a finding that NIE's costs were efficient in the past does not provide any assurance on the efficiency or reasonableness of NIE's expenditure forecasts.

7.22 Nonetheless, we recognize that NIE and its consultants have put considerable effort into work to allow for like-for-like comparisons between the costs of NIE and the GB DNOs, despite differences in the regulatory reporting framework between Northern Ireland and GB. These efforts have made substantial contributions to our own cost assessment work.

7.23 We have developed an approach to cost assessment that differs from that taken by NIE and by the UR in order to address the concerns above and to make the best use of the available information on the costs of the GB DNOs. In summary:

(a) In relation to NIE's network investment (including asset replacement and load-related expenditure), we have allocated NIE's expenditure forecasts between the categories of direct and indirect costs. For direct costs, we have determined an allowance for NIE based on a project-level review of NIE's capital investment plan. We have not used the implied element of indirect costs in NIE's plan.

(b) We have carried out a separate cost assessment for NIE's indirect costs and a category of costs that we refer to as inspections, maintenance, faults and tree cutting (IMF&T). The latter includes the main elements of what Ofgem refers to as network operating costs, which are a type of direct cost in Ofgem's terminology. We have produced an allowance for NIE's total indirect and IMF&T costs using estimates of an efficient level of costs based on our benchmarking of GB DNOs.

7.24 The two elements above cover the majority of NIE's costs, but not all of them. There are a number of other elements to our cost assessment work. For instance, NIE's substantial rates liability is not captured in the direct or indirect cost analysis above. Further, NIE carries out functions such as meter reading and meter replacement which are not done by the DNOs in GB. We have carried out separate assessments of these other elements, drawing on information provided by NIE and the UR.

7.25 Our analysis of NIE's indirect costs and IMF&T costs covers what NIE reports as opex and costs that NIE reports as capex. We need to produce separate allowances for opex and capex so that we can determine what costs should be funded through NIE's RAB and what costs should be covered by annual allowances during the price control period. To do so, we allocate our proposed allowance for indirect and IMF&T costs according to 2009/10 data on the relative proportions of NIE's opex and capex in these categories.

Structure of our work on cost assessment

7.26 In light of the approach set out above, we have structured our work on cost assessment into three main categories:

(a) *Indirect costs and IMF&T costs.* We make an allowance for NIE's indirect costs and its costs for inspections, maintenance, faults and tree cutting based on econometric benchmarking analysis using cost data from NIE and the 14 DNOs in GB.

(b) *Direct costs of core network investment.* This covers the direct costs of NIE's asset replacement investment as well as the load-related investment on NIE's distribution and transmission networks. It excludes indirect costs and the costs relating to IMF&T which are covered above. Our approach to cost assessment for this category of costs is based on a review of a network investment plan prepared by NIE, drawing on input from engineering consultants BPI.

(c) *Other elements of cost assessment.* This covers a number of other elements of NIE's costs which are not captured in *(a)* or *(b)* above.

7.27 We provide our cost assessment for these three categories in Sections 8, 9 and 10 respectively.

Adjustments for real price effects and future productivity improvement

7.28 We propose that, as for the current licence conditions, the restrictions on NIE's maximum regulated revenue are adjusted each year according to changes in the RPI.

7.29 All the figures that we have used for our cost assessment are in 2009/10 prices. This price was used for UR's RP5 price control review and is used for NIE's expenditure forecasts.

7.30 As part of our cost assessment we have made adjustments to the cost allowances based on 2009/10 prices:

(a) We have applied annual adjustment factors which are intended to take account of the extent to which we expect the input prices that NIE faces (eg for wages and materials) to grow by more or less than the annual change in the RPI. The factors relate to what we call 'real price effects' or RPEs in line with Ofgem's terminology.

(b) We have assumed that NIE will be able to make ongoing productivity improvements over time at a rate of 1 per cent per year for both opex and capex.

7.31 These adjustments do not apply to the allowances for rates or licence fees.

7.32 We provide more information on these adjustments in Section 11.

Overview and synthesis of cost assessment

7.33 This section sets out the provisional determination from our cost assessment which provide inputs to the financial model used to assess the likely impact on NIE's maximum regulated revenue and RAB.

7.34 We provide separate tables for capex used to calculate additions to NIE's RAB and for opex.

7.35 The figures in Tables 7.2 and 7.3 are calculated before the application of adjustments for productivity and RPEs and the figures in Tables 7.4 to 7.7 are calculated after adjustments for productivity and RPEs (see Section 11).

TABLE 7.2 **Summary table: capex before RPEs and productivity**

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Network investment direct costs:						
Distribution RAB	24.0	30.7	38.2	38.2	38.2	19.1
Transmission RAB	3.3	6.0	24.9	24.9	24.9	12.4
Benchmarked allowance for capitalized costs:						
Indirect & IMF&T costs (excluding tree cutting)	20.4	20.4	20.4	20.4	20.4	10.2
Tree cutting: Distribution RAB	4.8	4.8	4.8	4.8	4.8	2.4
Tree cutting: Transmission RAB	0.2	0.2	0.2	0.2	0.2	0.1
Non-network capex	1.5	4.0	3.7	3.7	3.7	1.8
Metering capex:						
Distribution RAB	1.5	1.5	2.6	2.6	2.6	1.3
Keypad RAB	1.8	1.8	4.4	4.4	4.4	2.2
Allocation of overheads to Distribution RAB	0.1	0.1	0.1	0.1	0.1	0.0
Allocation of overheads to Keypad RAB	0.1	0.1	0.2	0.2	0.2	0.1
Connection charges funded through Distribution RAB	5.0	2.5	0.8	0.0	0.0	0.0
Total	62.7	72.1	100.3	99.5	99.5	49.8

Source: CC analysis (rounded).

TABLE 7.3 **Summary table: opex before RPEs and productivity**

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Indirect costs and IMF&T costs allocated to opex	26.5	26.5	26.5	26.5	26.5	13.2
Enduring Solution	5.2	5.0	4.7	4.3	4.1	2.1
Meter reading	3.4	3.4	3.4	3.4	3.4	1.7
Other operating costs relating to keypad meters	0.2	0.2	0.2	0.2	0.2	0.1
Allocation of NIE admin costs to meter reading	0.3	0.3	0.3	0.3	0.3	0.2
Allocation of NIE admin costs to market opening	0.3	0.3	0.3	0.3	0.3	0.2
Additional allowance for atypical severe storms	0.2	0.2	0.2	0.2	0.2	0.1
AGU arrangements	0.0	0.0	0.0	0.0	0.0	0.0
Total opex subject to productivity and RPEs	36.1	35.9	35.6	35.3	35.0	17.5
Items not subject to productivity and RPEs:						
Rates	12.6	12.7	12.7	12.8	12.9	6.5
Licence fees	1.9	1.9	1.9	1.9	1.9	1.0
Deduction: connection charge contribution to O&M	–0.6	–0.6	–0.6	–0.6	–0.6	–0.3
Total	50.0	49.9	49.6	49.4	49.2	24.7

Source: CC analysis (rounded).

TABLE 7.4 **Summary table: capex after RPEs and productivity**

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Network investment direct costs:						
Distribution RAB	23.0	29.2	36.2	36.1	35.8	17.8
Transmission RAB	3.1	5.7	23.6	23.5	23.3	11.6
Benchmarked allowance for capitalized costs:						
Indirect & IMF&T costs (excluding tree cutting)	19.6	19.4	19.4	19.3	19.1	9.5
Tree cutting: Distribution RAB	4.6	4.6	4.6	4.6	4.5	2.3
Tree cutting: Transmission RAB	0.2	0.2	0.2	0.2	0.2	0.1
Non-network capex—5-year RAB	1.4	3.8	3.5	3.5	3.5	1.7
Metering capex:						
Distribution RAB	1.5	1.5	2.5	2.5	2.5	1.2
Keypad RAB	1.7	1.7	4.2	4.2	4.2	2.1
Allocation of overheads to Distribution RAB	0.1	0.1	0.1	0.1	0.1	0.0
Allocation of overheads to Keypad RAB	0.1	0.1	0.1	0.1	0.1	0.1
Connection charges funded through Distribution RAB	4.8	2.4	0.8	-	-	-
Total	60.1	68.5	95.1	94.0	93.2	46.4

Source: CC analysis (rounded).

TABLE 7.5 **Summary table: opex after RPEs and productivity**

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Opex subject to RPEs and productivity	34.3	33.9	33.6	33.2	32.8	16.3
Items not subject to RPEs and productivity:						
Rates	12.6	12.7	12.7	12.8	12.9	6.5
Licence fees	1.9	1.9	1.9	1.9	1.9	1.0
Deduction: connection charge contribution to O&M	–0.6	–0.6	–0.6	–0.6	–0.6	–0.3
Total	48.2	47.9	47.6	47.3	47.0	23.5

Source: CC analysis (rounded).

TABLE 7.6 **Summary table: RAB additions (after RPEs and productivity) arising from cost assessment**

	Apr–Sep 2012	*Oct–Dec 2012*	*Jan–Sep 2013*	*Oct 2013–Sep 2014*	*Oct 2014–Sep 2015*	*Oct 2015–Sep 2016*	*Oct 2015–Sep 2016*
Distribution	23.3	11.7	36.4	50.5	51.1	50.5	50.1
Transmission	2.7	1.3	5.7	19.8	30.9	30.7	30.5
Keypad metering	0.9	0.5	1.5	3.1	4.3	4.3	4.3
New 5-year RAB—Transmission	0.2	0.1	0.5	1.1	1.5	1.5	1.5
New 5-year RAB—Distribution	2.9	1.5	5.4	7.3	6.8	6.7	6.7
Total	30.0	15.0	49.3	81.8	94.5	93.6	93.0

Source: CC analysis (rounded).

Note: The periods shown in this table reflect those used in the financial model.

TABLE 7.7 **Summary table: opex allowance (after RPEs and productivity) arising from cost assessment**

	Apr–Sep 2012	*Oct–Dec 2012*	*Jan–Sep 2013*	*Oct 2013–Sep 2014*	*Oct 2014–Sep 2015*	*Oct 2015–Sep 2016*	*Oct 2015–Sep 2016*
Allocated to Transmission	3.5	1.7	5.2	6.9	6.8	6.8	6.8
Allocated to Distribution	19.7	9.8	29.4	39.0	38.7	38.5	38.3
Licence fees:							
Transmission	0.1	0.1	0.2	0.3	0.3	0.3	0.3
Distribution	0.8	0.4	1.2	1.6	1.6	1.6	1.6
Total	24.1	12.0	36.0	47.7	47.4	47.2	47.0

Source: CC analysis (rounded).

Note: The periods shown in this table reflect those used in the financial model.

7.36 In the tables above we have presented our provisional cost allowances separately in respect of Transmission and Distribution, reflecting our provisional decision that each should be subject to separate revenue control. We used the following method to allocate capex and opex between transmission and distribution. For capex, some of the cost categories are already attributed to either transmission or distribution (eg network investment direct costs are split between transmission and distribution and all metering costs are attributable to distribution). For residual elements of capex (eg indirect costs and non-network capex) we allocated the costs in each year between transmission and distribution according to the relative share of capex in that year which was already attributed to transmission. For opex, we used an approximate figure of 15 per cent to allocate the total allowance for opex to transmission. This figure reflects the assumption used in Section 8 that 7.5 per cent of NIE's indirect costs are for the 275 kV network, which we have doubled on the basis that NIE's transmission activities cover 275 kV and 110 kV infrastructure. We will consider these allocations further for our final determination.

7.37 The profile of the RAB additions in Table 7.6 above reflects an attempt to align the profile of our expenditure allowance for NIE's network investment with NIE's actual expenditure in 2012/13 and its forecast expenditure in 2013/14.For our provisional determination, we have used the UR's financial model for NIE which it used for its RP5 final determination. That financial model is not organized into financial years running April to March. For the latter part of the price control period the financial years run from October to September. For part of the price control period there are a series of periods of less than 12 months which reflect changes over time in the UR's time period for its RP5 price control and specific features of its Final Determination. We have allocated the figures above into the time periods in the UR's financial model by spreading costs evenly over the quarters or half-year periods to which they apply (eg we have input an allowance for the period October 2015 to September 2016 by taking 50 per cent of the allowance in Tables 7.4 and 7.5 for the financial year to March 2016 and 50 per cent of the allowance for the financial year to March 2017).

Items not included in our cost assessment

7.38 There are several items of expenditure which are not currently included in our cost assessment and around which there remains some uncertainty..This is because our provisional price control design (see Section 5) does not contain a Dt term and we are uncertain how much has been spent on these items. These are:

(a) RP4 carry-over items; and

(b) projects approved on 22 February 2013 by the UR.

RP4 carry-over items

7.39 This is expenditure related to the recovery of costs which have been approved by the UR under the Dt term of the licence in RP4.

7.40 This expenditure amounts to £8.5 million and covers IT (an upgrade to NIE's Network Management System), SONI pension deficit repair (relating to NIE's disposal of SONI in 2009), the North South Interconnector (covering the public inquiry process and planning approval) and renewable projects approved by the regulator in RP4.

Projects approved by the UR on 22 February 2013

7.41 This expenditure, which totals £25.8 million,[2] relates to three projects which were approved by the UR under the Dt term of NIE's transmission licence on 22 February 2013.[3] We noted that this project appears to have been approved by the UR on a cost pass-through basis.[4]

7.42 These projects are part of NIE's medium term plan (MTP) relating to network development to accommodate increased renewable generation. The MTP will increase the capacity of the 110 kV network and increase flows up to the 275 kV network. They will be added to the transmission renewables RAB and will be amortized at 3 per cent a year for the first 20 years and 2 per cent a year for the next 20 years.

7.43 These projects have not been included in the elements of our cost assessment presented above and we have not included this expenditure within our financial model.

Potential additional transmission investment

7.44 We have included a mechanism within our price control design which allows the UR to adjust NIE's revenue control, during the price control period, to allow for the costs of additional investment to increase the capacity of the transmission system (see Section 5). The amount of this investment which will take place before September 2017 is uncertain.

7.45 We asked NIE to forecast potential investment in this area. Table 7.5 shows that it forecast the potential for around £111.9 million of such investment.

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[2] 2009/10 prices.
[3] www.uregni.gov.uk/uploads/publications/Medium_Term_Plan_Final_Decision.pdf.
[4] ibid, p6 & 7.

TABLE 7.5 **Potential additional transmission load-related expenditure, 2009/10 prices**

	Prior to Sept 2014	*Oct 2016–Sept 2017*	*Oct 2016–Sept 2017*	*Oct 2016–Sept 2017*	*Total*
Potential additional transmission load-related expenditure	0.3	9.6	45.5	56.5	111.9

Source: NIE, CC analysis.

Note: Projects included are:
1. CPS – MAG 275kV Overhead Line Conductor Replacement (T18);
2. Castlereagh and Tandragee Voltage Support (T24);
3. North West Reactive Compensation (T25);
4. Construction for third cct Omagh–Tamnmore;
5. North South Interconnector – Construction of Turleenan and 400 kV circuit to border ;
6. Omagh–Turleenan 275 kV circuit pre construction; and
7. Kells–Coleraine 110 kV reinforcement.

We have excluded projects recoverable through wind developer contributions and the BPS 110 kV switchboard (T26, which is included in our core network investment allowance).

7.46 We noted that around half (£57.7 million) of this potential additional investment related to the North–South Interconnector, which we understand is currently highly uncertain.

7.47 We also noted that NIE's forecasts are purely indicative and any additional adjustments to the price control would be dependent on the UR's assessment

8. Benchmarking analysis for indirect costs and IMF&T costs

Introduction

8.1 We have made a provisional determination of an annual allowance for NIE's indirect costs and its costs for IMF&T. Our provisional determination is based on the results from benchmarking analysis covering NIE and 14 electricity distribution network companies in GB.

8.2 Both NIE and the UR carried out econometric benchmarking analysis for NIE's indirect costs and IMF&T costs. We sought to build on the analysis carried out by the parties. In line with the analysis of NIE and the UR, our analysis relies on cost categorizations established by Ofgem which the GB DNOs are required to use for reporting their costs. The costs we label 'IMF&T' costs represent the majority but not all of a wider category of costs that Ofgem labels 'network operating costs'.

8.3 We provided information on these cost categories in Section 7 (Table 7.1). Indirect costs include costs in areas such as network design and engineering, project management, network control centre, human resources, finance and regulation. For both NIE and the GB DNOs, the category of indirect costs includes costs that are capitalized and costs that are not capitalized. The same is true for the costs falling under the category of IMF&T costs.

8.4 Our benchmarking analysis therefore cuts across NIE's capex and its opex. Because we maintain the approach of including forecast capex in NIE's RAB, we need to separate our allowance for indirect and IMF&T costs between operating and capex. We do this by applying an allocation factor based on our calculation of the proportion of NIE's 2009/10 indirect costs and IMF&T costs that were capitalized by NIE.

8.5 The base year for our analysis is 2009/10. This year was the focus of the work carried out by NIE and the UR as part of the RP5 price control review. Whilst we have brought more recent data from the GB DNOs to bear on our econometric analysis, we use our benchmarking analysis to produce estimates of an efficient level of costs for NIE for the financial year 2009/10. For the provisional determinations from our cost assessment that are presented in Section 7 we extrapolate over the period to 30 September 2017 by applying a series of annual adjustments for RPEs and ongoing productivity improvement.

8.6 This section describes our benchmarking analysis and how we have interpreted the results. It is organized into three main steps:

(a) We produce estimates of NIE's historical indirect costs and network operating costs that are intended to be consistent, as far as possible, with the cost reporting categories and definitions applicable to the cost data we have obtained from Ofgem for GB DNOs. We refer to these as 'benchmarked costs'. See paragraphs 8.8 to 8.31.

(b) We carry out benchmarking analysis using relatively simple econometric models to compare the costs of NIE against GB DNOs. As part of the benchmarking analysis we make some adjustments to render NIE's indirect costs more comparable with those of GB DNOs. See paragraphs 8.32 to 8.97.

(c) We draw on results from the benchmarking analysis, and NIE's historical costs, to produce an assessment of level of NIE's 'benchmarked costs' over the price control period if it operated efficiently and provided the same services and outputs as the distribution companies in our sample did in 2009/10. See paragraphs 8.98 to 8.146. This assessment excludes any potential impacts from input price inflation (or real price effects) and future productivity improvements. These are considered in Section 11.

8.7 This section is supported by five appendices:

(a) Appendix 8.1 provides a summary of the UR's approach to the calculation of a proposed allowance for NIE's controllable opex, with particular attention to the econometric benchmarking analysis used by the UR.

(b) Appendix 8.2 highlights some of the criticisms of the UR's approach and analysis that are raised by NIE. It sets out NIE's alternative proposals for an allowance for controllable opex.

(c) Appendix 8.3 provides further information on the method and data we used to calculate an estimate of NIE's indirect costs that is comparable with the indirect cost data reported by GB DNOs.

(d) Appendix 8.4 provides further information on the method we used to make adjustments to the costs of NIE and DNOs in GB to take account of data on differences in wages between different parts of the UK.

(e) Appendix 8.5 provides further information on the econometric model specifications used for our benchmarking analysis, the data sources and results.

Step (a): calculation of benchmarked costs for NIE

8.8 We have carried out econometric benchmarking analysis using two different categories of costs:

(a) indirect costs only; and

(b) indirect costs plus costs of IMFT&T.

8.9 This subsection describes how we have made estimates of NIE's costs for these two categories. It is organized as follows:

(a) We first identify the data we use for the costs of GB DNOs (see paragraphs 8.10 to 8.18). Our calculation of NIE's costs for the benchmarking analysis is intended to be aligned with the basis on which this data is provided.

(b) We describe our approach to the calculation of NIE's indirect costs (see paragraphs 8.19 to 8.23).

(c) We describe our approach to the calculation of NIE's costs for IMF&T (see paragraphs 8.24 to 8.30).

(d) We show the results of our calculations for the costs of NIE, which we use for our benchmarking analysis (see paragraph 8.31).

Data source for GB DNO cost data

8.10 Ofgem does not regularly publish cost data for GB DNOs. Whilst these companies fill in detailed reporting templates on costs and other matters each year, the data is not routinely published.

8.11 In December 2009, as part of its final proposals from its DPCR5 price control review, Ofgem published the financial model that it used to calculate price controls for the GB DNOs for the five-year period from 1 April 2010.[1] This model took the form of an Excel workbook. The Excel workbook contains historical data on the costs of GB DNOs, including data reported for indirect costs (split between 'Indirects closely associated with directs' and 'Business support' costs) and data for network operating costs (split between 'I&M' (inspections and maintenance), 'faults', 'trees' and 'other').

8.12 In the absence of other publicly available data, the consultants working for NIE and the UR used this cost data from Ofgem's DPCR5 financial model for the purposes of benchmarking NIE with GB DNOs.

8.13 This cost data available from the DPCR5 financial model has some limitations:

(a) Historical cost data are only available for years to 2008/09. For 2009/10 the data is forecasts of spend (albeit forecasts made part-way through the year to which

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[1] www.ofgem.gov.uk/ofgem-publications/46764/financial-issues-dpcr5-20091204-final-proposals-dnos.xls, retrieved 23 October 2013.

they apply). The base year used by the UR and NIE for the price control review was 2009/10.

(b) There is a lack of transparency or clarity as to the nature of the historical cost data in the published DPCR5 financial model. Ofgem's reporting requirements and definitions have changed over time. Further, as part of the DPCR5 price control review process, Ofgem requested additional cost data from companies. It is not clear from the publicly available information exactly what the cost data reported in the DPCR5 financial model relates to.

8.14 The lack of transparency has been particularly problematic in this inquiry in relation to the treatment of costs attributed to connections activities. Both Frontier Economics (Frontier) (in analysis for NIE) and CEPA (in analysis for the UR) took the view that the historical indirect cost data published as part of the DPCR5 financial model excluded indirect costs attributed to connections, but this did not seem to us to be consistent with the cost reporting requirements applicable at the time. Neither Frontier nor CEPA provided references or other evidence to substantiate that view. We put some follow-up questions to Frontier and CEPA and it seems that their view on the costs data that they have used reflects their knowledge or recollections gained from work for Ofgem or GB DNOs.

8.15 We asked Ofgem a series of questions to clarify the basis for the historical indirect cost data in the published DPCR5 financial model. Ofgem told us that:

(a) the indirect cost data in the DPCR5 financial model for years 2008/09 and 2007/08 should include any indirect costs estimated as relating to the elements of connection costs that companies did not recover through connection charges or customer contributions;

(b) the indirect cost data in the DPCR5 financial model for these years should exclude any indirect costs estimated as being attributable to sole use connections; and

(c) the indirect cost data in the DPCR5 financial model for these years should include any indirect costs estimated as being attributable to connection reinforcement that was charged to the connecting customer.

8.16 On that basis, the benchmarking comparisons submitted by NIE and the UR do not involve a like-for-like treatment of connection costs: some costs that GB DNOs attribute to connections are included within the DPCR5 financial model data whereas the indirect cost estimates for NIE used by Frontier and CEPA are intended to exclude all NIE indirect costs attributed to connections. The effect is to understate NIE's costs relative to the GB DNOs, which may have a significant impact on the results from the benchmarking analysis.

8.17 In light of these and other issues, we have not used the data from the DPCR5 financial model for the econometric benchmarking analysis we use for our provisional determinations. Instead, we obtained cost data directly from Ofgem. The data is for the following financial years: 2009/10; 2010/11 and 2012/13. The data is reported on the basis of the new regulatory reporting rules introduced following Ofgem's DPCR5 price control review. This data provides us with a greater degree of transparency because we can trace the data provided by Ofgem back to published reporting rules and to the data templates that companies are required to complete.

8.18 Data is not available in the newer RIGs format for years before 2009/10. Further, Ofgem told us that because of new reporting requirements that were introduced, some of the data reported in 2009/10 (the year before the new reporting templates formed part of the DPCR5 reporting arrangements) was on a best endeavours or trial basis. Ofgem said that it did not have data for years before 2009/10 that would allow a full decomposition of indirect costs between costs attributed to connections and costs not attributed to connections.

Indirect cost estimate for NIE

8.19 We have sought to calculate estimates of NIE's indirect costs and IMF&T costs that are consistent, as far as possible, with the reporting basis used for the Ofgem data on GB DNOs. We have built on the estimates and methods developed by Frontier and CEPA and a series of further submissions from NIE and the UR on the matter.

8.20 Our data for GB DNOs covers 2009/10, 2010/11 and 2011/12. We did not have a full set of data to calculate indirect and IMF&T costs for 2010/11 and 2011/12. NIE told us that it would take substantial additional resource and time to provide the data to enable us to reproduce our calculations of indirect and IMF&T costs for 2010/11 and 2011/12 and this posed risks of delaying our inquiry. We did not consider that requiring NIE to provide data for these two additional years would represent proportionate regulation.

8.21 We summarize our calculation of NIE's indirect costs in 2009/10 as follows:

(a) We started with data reported for controllable operating expenditure and capitalized overheads in NIE's BPQ response (opex response 11 February 2011). We included in our calculation of NIE's indirect costs the individual elements of its controllable operating expenditure and capitalized overheads that seem to fall under the definition of indirect costs, excluding the charges to NIE from NIE Powerteam.[2]

[2] In contrast to the approach adopted by CEPA and Frontier, we do not start with NIE's total controllable opex and make deductions, though we have carried out a separate reconciliation between our estimate of NIE's indirect costs and NIE's total controllable opex.

(b) We included the estimates developed by Frontier of the portion of NIE Powerteam's costs that should be categorized as indirect costs. Frontier's estimates are calculated using a detailed cost mapping exercise. CEPA's benchmarking analysis for the UR also relied on Frontier's estimates.

(c) We included costs attributed to wayleaves. These are not categorized as part of NIE's controllable opex in NIE's BPQ response but they fall under Ofgem's definition of indirect costs. Consistent with the approach taken by Frontier and CEPA, we deduct the element of these costs attributable to wayleave administration by NIE Powerteam to avoid double-counting in relation to NIE Powerteam costs included in *(b)* above.

(d) We included some other costs incurred by NIE in 2009/10 which were not reported under controllable opex but which nonetheless seemed part of its indirect costs and relevant to comparisons with GB DNOs.

(e) We made a number of further adjustments in light of submissions from the parties. These included adjustments proposed by NIE to convert the reported cost data into a cash basis (eg removing effects of provisions and accruals and prepayments that are not incurred as part of the ordinary level of business) to be consistent with Ofgem's cash reporting rules. They also include adjustments to remove estimates of costs incurred by NIE which are attributed to other businesses or external parties and adjustments to remove an allocation of administrative costs or overheads to functions carried out by NIE but not GB DNOs (eg meter reading).

8.22 The costs included under *(a)* and *(b)* include current service pension costs of NIE and NIE Powerteam. In contrast, pension costs were not included in the benchmarking analysis carried out by Frontier and CEPA because the DPCR5 financial model data that they used explicitly excluded pension costs. However, the indirect costs data that Ofgem provided us with do include pension costs. As pension costs are one element of labour costs, we consider it better to carry out benchmarking with ongoing pension costs included (but excluding historical deficit pension costs).

8.23 Appendix 8.3 provides a more detailed explanation of our approach to the calculation of an estimate of NIE's indirect costs.

Inspections, maintenance, faults and tree cutting costs

8.24 Frontier's benchmarking analysis for NIE included comparisons of indirect costs and separate comparisons of what Frontier called 'R&M' costs. CEPA's analysis for the UR included benchmarking analysis that compared measures of costs that comprised the sum of indirect costs and the costs labelled 'R&M' costs by Frontier.

8.25 Frontier's analysis of 'R&M' costs were based on data from Ofgem's DPCR5 financial model for categories of costs that Ofgem defines as network operating costs. In its DPCR5 financial model, the historical data on network operating costs is broken into four categories: *(a)* I&M; *(b)* faults; *(c)* tree cutting; and *(d)* other. Frontier's analysis focused on the first three categories of network operating costs. Frontier referred to these as 'Repairs and Maintenance (R&M) costs' (Frontier, June 2011, p8).

8.26 We too have included these costs within the scope of our benchmarking analysis, but we use different terminology. Frontier's use of the term 'R&M' is potentially confusing. The costs covered by this term in Frontier's analysis include costs which are capitalized by NIE and do not correspond to what NIE reported under the heading of 'repairs and maintenance' in its response to the RP5 BPQ on opex. They also include costs which NIE does not itself treat as repairs and maintenance (eg tree-cutting costs). We used the term IMF&T to distinguish these costs from repairs and maintenance and to represent the costs from the three categories above that we cover: inspections, maintenance, faults and tree cutting. Where the context does not require as much precision, we sometimes refer to these costs as network operating costs as they represent a large proportion of Ofgem's definition of network operating costs.

8.27 There is a difference in our data source. In line with our approach to indirect costs, we used data provided by Ofgem for the financial years 2009/10, 2010/11 and 2011/12 rather the data from the DPCR5 financial model. The network operating costs available for these years are presented under the following headings: *(a)* inspections and maintenance; *(b)* trouble call; *(c)* tree cutting; *(d)* severe weather—atypical; and *(e)* NOCs Other. We have used data for *(a)*, *(b)* and *(c)* which corresponds to the costs reported for inspections, maintenance, faults and tree cutting under the previous reporting definitions and the DPCR5 financial model. Neither NIE nor the UR raised concerns about any changes in the definitions of Ofgem's network operating costs adversely affecting the benchmarking analysis.

8.28 The Frontier benchmarking analysis includes estimates of NIE's costs for the category we refer to as IMF&T costs, calculated using costs recorded by NIE against various activities falling within IMF&T. The costs recorded by NIE include indirect costs whereas the IMF&T cost category should include direct costs only. Frontier therefore makes an adjustment to NIE's recorded costs to exclude indirect costs. This involves a decomposition of NIE's recorded costs into two categories:

(a) materials and bought-in services (MBIS), which are assumed to be entirely direct costs; and

(b) NIE Powerteam costs, which include direct costs and indirect costs.

8.29 Frontier's calculation of IMF&T costs includes an adjustment to *(b)* which is intended to strip out the element which is indirect costs so that estimated IMF&T costs include direct costs. This adjustment is calculated using an estimate of the proportion of NIE Powerteam costs that are direct costs.

8.30 We have used the estimates of IMF&T costs produced by Frontier, but with a significant adjustment. Frontier's benchmarking analysis used cost data for GB DNOs from Ofgem's DPCR5 financial model which was reported as excluding pension costs. In contrast, our benchmarking analysis includes ongoing pension costs. We produced a revised estimate of the proportion of NIE Powerteam costs that are direct costs which included pension costs within direct costs. Frontier's estimate of NIE Powerteam's direct costs was around 13 per cent higher if pensions were included in the analysis than if pensions were excluded. So we increased the estimated direct costs for NIE Powerteam by 13 per cent and recalculated IMF&T costs on this basis.

NIE's indirect and IMF&T costs

8.31 Table 8.1 summarizes the cost figures we have calculated for NIE and used in our benchmarking. These are cost data before any adjustments to exclude costs attributed to connections or to NIE's 275 kV network which are discussed under step *(b)* below.

TABLE 8.1 **Costs for NIE, 2009/10, for benchmarking analysis**

	£m
Indirect costs	47.1
IMF&T costs	14.2
Indirect and IMF&T costs	61.3

Source: CC analysis.

Step (b): benchmarking analysis

8.32 The second step of our approach is to carry out benchmarking analysis. We use a number of different models and methods and compare companies in several different ways (eg indirect costs only or indirect costs plus IMF&T costs).

8.33 This subsection provides more information on the methods we have used for benchmarking analysis and presents results. It is organized as follows:

(a) We describe our approach to cost adjustments for differences in wage rates between Northern Ireland and other parts of the UK (paragraphs 8.36 to 8.47).

(b) We describe our approach to making an adjustment for the fact that owns and maintains 275 kV network infrastructure whereas GB DNOs do not operate network infrastructure at this voltage level (paragraphs 8.48 to 8.57).

(c) We describe our approach in relation to indirect costs that are attributed to connections and excluded services (paragraphs 8.58 to 8.66).

(d) We describe our approach in relation to the treatment of costs relating to wayleaves (paragraphs 8.67 to 8.69).

(e) We describe the econometric models we have used (paragraphs 8.70 to 8.80).

(f) We discuss the choice of the cost benchmark for our analysis (paragraphs 8.81 to 8.85).

(g) We provide results from the analysis (paragraphs 8.86 to 8.97).

8.34 We provide further information on our adjustments for regional wage differences in Appendix 8.4. We provide further information on our econometric model specifications, results and data sources in Appendix 8.5.

8.35 We have built on the extensive work done by the consultants for NIE and the UR. We have not sought to carry out more granular benchmarking analysis (eg potential benchmarking analysis for more granular cost categories within indirect costs, which Ofgem includes within its suite of analytical approaches for benchmarking of GB distribution companies). Nor have we sought to develop more sophisticated econometric models. The disputes between the parties in their initial submissions to us concerned detailed aspects of the methods and calculations used for benchmarking. Neither party sought to reject the principle of benchmarking NIE against GB DNOs or to reject the type of high-level econometric models that the consultants working for the parties have used. Further, we have been constrained by the information available on NIE's costs which is not reported to the same degree of granularity as GB DNOs.

Wage adjustments

8.36 In its benchmarking analysis for the UR, CEPA made adjustments to the cost data for NIE and each of the GB DNOs to try to take account of differences in wage rates between different parts of the UK. Frontier made no such adjustment in its original benchmarking analysis and this difference of approach explains a large part of the difference in results between CEPA and Frontier.

8.37 NIE objected to the principle of making wage adjustments on the basis that whilst wage adjustments would tend to worsen NIE's apparent performance relative to GB DNOs, there might be other differences between NIE and those DNOs that were not taken into account but which would improve its performance. NIE also submitted that if wage adjustments were to be made, they should be calculated using an alternative method set out in analysis by Frontier. This alternative method gives rise to a very small wage adjustment for NIE.

8.38 We have considered wage adjustments as part of our comparisons across different electricity distribution companies in the UK. Wage differences between different parts of the UK could lead to substantial differences in costs. There are publicly available data sources that allow wage comparisons between regions within the UK. We do not accept NIE's argument that we should not make regional wage adjustments unless we make adjustments for other factors that may improve NIE's relative performance in the benchmarking exercise. There will be many factors that affect companies' relative costs that we cannot take appropriate account of in the benchmarking exercise.

But that should not prevent us taking account of specific factors where we consider that an adjustment is likely to make a positive contribution to the cost comparisons between companies.

8.39 We have reviewed the submissions of the parties on the calculation of wage adjustments. We also thought more widely about what adjustment methods are possible with the available data.

8.40 The data source we have used is weekly wage data from the Annual Survey of Hours and Earnings (ASHE). For the UK and the regions of GB this data was obtained from the Office for National Statistics, while for Northern Ireland it was obtained from the Northern Ireland Statistics and Research Agency. We also considered the ASHE hourly wage data.[3]

8.41 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.

8.42 We have produced results from benchmarking analysis using three different wage adjustment methods to adjust each company’s cost data before estimation of the econometric model. These methods are summarized as follows (we provide more detailed information in Appendix 8.4):

[3] We took this from the Excel model accompanying Frontier’s updated benchmarking analysis (2 August 2013).

(a) *Method WA1.* We use an allocation carried out by Frontier for NIE of the NIE and NIE Powerteam workforce to the most granular occupational categories available in the ASHE regional wage statistics (four-digit SOC code). For each region in the UK, we calculate a weighted average of regional wages (relative to the UK as a whole) based on the ASHE wage data for those occupational categories (relative to the UK as a whole), with weights determined by the weight given to each occupational category in the Frontier allocation for NIE (we use the same occupational categories and weights for the GB DNOs). We adjust the cost for each company according to the weighted average of regional wages relative to the UK as a whole for the region that the DNO operates in.

(b) *Method WA2.* This wage adjustment method uses the same approach as for WA1 except that, for each occupational category, we replace the ASHE wage data used in method WA1 (four-digit SOC code) with wage data for the more aggregated occupation category that it falls under (ie the three-digit SOC code that the relevant four-digit SOC code falls under). This approach uses wage data for which there is a large sample size than for method WA1.

(c) *Method WA3.* This method for wage adjustment uses ASHE data on average regional wages relative to UK averages to adjust the costs of each company. It does not take any specific account of the occupational categories of staff working for NIE or other electricity distribution companies.

8.43 In addition, we have produced results from benchmarking analysis that do not involve any wage adjustments. We label this approach method WA0.

8.44 As far as possible, we calculate the wage adjustments using annual data on regional wages that are averaged over a five-year period. This helps to reduce concerns about small sample sizes in the ASHE regional wage data.

8.45 In all cases we use data on average wages rather than median wages. Average wages are more relevant when forecasting the total costs across a group of staff within the occupational categories used. In contrast, median wages would be more relevant to a forecast of the wages of a particular employee picked at random from those categories.

8.46 Frontier identified that mean wages may be more prone to sampling error than median wages and that this might be a reason to prefer median wages. We do not consider this point sufficient to favour median wages. However, it does add to the case for wage adjustment methods that make use of a larger sample size.

8.47 There is also a choice between whether to use data on weekly wages or hourly wages. CEPA uses weekly wages. Frontier uses hourly wages. We calculated potential adjustments for both weekly and hourly wages (see Appendix 8.4). We consider weekly wages the better choice. Weekly wages seem more relevant to the type of salaried occupations that are relevant to the workforce of NIE and NIE Powerteam. In any event, as indicated in Appendix 8.4, the differences between our calculated wage adjustments on an hourly and weekly basis are generally small. The main exception is the wage adjustments for some DNOs under method WA1; that method uses the most granular data and, in turn, relies on data for which the sample size is smaller. As discussed under step *(c)*, we have given most weight to wage adjustment method WA2 for which the impact (if any) on each DNO's costs of using weekly rather than hourly wages is of the order of 1 per cent.

Treatment of costs attributed to 275 kV network

8.48 NIE's electricity network infrastructure is divided into a transmission system and a distribution system. The transmission system includes lines operated at 275 kV and

110 kV and the distribution system includes lines operated at voltages of 33 kV and below.

8.49 The data from Ofgem that we have used concerns the costs of the 14 regional licence DNOs in GB. These companies differ from NIE in the following ways:

(a) The 12 DNOs in England and Wales operate networks with voltages up to 132 kV. In England and Wales, National Grid operates a separate transmission network at voltages of 275 kV and 400 kV.

(b) The two regional DNOs in companies in Scotland operate networks with voltages up to 33 kV. In Scotland, voltages of 132 kV and above are categorized as transmission and the transmission networks are operated by separate licensed entities that are subject to separate price controls from the DNOs.

8.50 The indirect costs and network operating costs of NIE will include costs relating to 275 kV network infrastructure. None of the GB DNOs operate 275 kV networks.

8.51 In its cost benchmarking analysis for NIE, Frontier made an allocation of NIE's costs with the aim of removing the element of costs attributed to 275 kV infrastructure before making comparisons with the costs of GB DNOs. Frontier's approach can be summarized as follows:

(a) 7.5 per cent of NIE's indirect costs are attributed to 275 kV network infrastructure, with the remaining 92.5 per cent of indirect costs attributed to the rest of NIE's transmission and distribution systems. The figure of 7.5 per cent is derived from Frontier's estimate of the proportion of NIE's RAB additions for transmission and distribution that is attributed to the 275 kV network, using information on the proportion of transmission capex relating to the 275 kV network over the period 2003 to 2010. The 7.5 per cent figure applies to 2009/10.

(b) For network operating costs (which Frontier refers to as ‘R&M’ costs), the majority of costs are allocated between 275 kV and sub-275 kV infrastructure through a detailed bottom-up analysis. Only a small percentage of these costs are allocated using the 7.5 per cent assumption.

8.52 CEPA’s October 2011 report presented benchmarking analysis that used the same 7.5 per cent adjustment for NIE’s 275 kV network as Frontier, with CEPA reporting as follows (p8):

> NIE’s submission estimated that approximately 7.5% of opex relates to the 275kV transmission network. We have considered this against estimates for capex carried out at 275kV and believe that this estimate is relatively robust, and as such have used the 7.5% adjustment to remove 275kV work from the opex estimate.

8.53 In making comparisons of NIE’s indirect costs against GB DNOs, we have also scaled down NIE’s indirect costs by 7.5 per cent, in line with the approach developed by Frontier and CEPA.

8.54 For IMF&T costs, we have made use of the more granular allocation of costs between 275 kV and the rest of NIE’s network available from Frontier’s analysis. This results in around 2.5 per cent of NIE’s IMF&T costs being allocated to 275 kV and removed from NIE’s costs before comparisons with GB DNOs.

8.55 A limitation of the approach used by Frontier and CEPA is that it overlooks the differences between Scotland and the rest of GB in the composition of the distribution network. The comparisons carried out by Frontier and CEPA do not seem to take account of the fact that the DNOs in Scotland do not operate 132 kV networks. The impact this has on results from benchmarking analysis for NIE is dependent on the details of econometric model used for benchmarking purposes. Frontier suggested that the effect would tend to overstate the relative efficiency of the two Scottish DNOs.

8.56 We have not found a practical alternative to the approach taken by Frontier and CEPA in relation to the Scottish DNOs. One option might be to exclude cost data from the two Scottish DNOs from the analysis because they do not include the costs associated with 110 or 132 kV infrastructure. But in other ways these companies are more similar to NIE than the DNOs in England and Wales (eg number of customers, sparsity of network) and it could be detrimental to the comparability of the sample with NIE to exclude them.

8.57 Another option might be to include in the benchmarking analysis some cost data reported by the transmission companies operating in Scotland, to bring costs related to 132 kV assets (and potentially 275 kV assets) into the cost comparisons with NIE. Whilst this was not practical for our inquiry, the UR and NIE might consider this for the future.

Treatment of costs attributed to connections and non-distribution activities

8.58 We also sought to exclude, as far as possible, indirect costs incurred by NIE that do not relate to its transmission or distribution activities (eg by deducting the value of recharges from NIE to other businesses for the recovery of costs incurred by NIE). Similarly we made adjustments to the GB DNO data to exclude costs attributed to non-distribution activities (ie activities that are not part of their distribution businesses).

8.59 We also considered adjustments for costs relating to new connections. Both Frontier and CEPA scaled down their estimate of NIE's indirect costs by around 20 per cent before making comparisons with the DNOs in GB in order to remove an estimate of the element of NIE's indirect costs that is attributable to connections activities. Frontier and CEPA stated that this adjustment was appropriate because the GB DNO data that they used on indirect costs excluded indirect costs attributable to connections. However, as discussed under step *(a)* above, we found that the estimate of NIE's indirect costs used by Frontier and CEPA did not involve the same treatment of connection costs as the GB DNO data from Ofgem's DPCR5 financial model (see paragraphs 8.11 to 8.17). We have not used the data from the DPCR5 financial model for the benchmarking analysis we present in this section.

8.60 We used cost data obtained directly from Ofgem which is reported under the RIGs reporting requirements established as part of the DPCR5 price control review. The data provided by Ofgem allows us to make comparisons of indirect costs between NIE and GB DNOs on a basis that excludes indirect costs attributed to connections and also on a basis that includes any indirect costs attributable to connections.

8.61 There are some reasons why it is better to carry out benchmarking analysis for costs excluding connections. For instance, different companies may carry out different volumes of connection activity, with impacts on their cost, but these differences may not be adequately captured in the econometric models we use. Alternatively, making comparisons of indirect costs without exclusion of connection costs makes the analysis less vulnerable to any inconsistencies in cost allocation methods used by the companies in the sample. Given the size of the adjustment to exclude connection costs for NIE (around 20 per cent), such inconsistencies could have a significant impact on the results.

8.62 We produced results for indirect costs with and without adjustments to exclude costs attributed to connections. We discuss under step *(c)* how we used these results in making a provisional determination of an indirect cost allowance for NIE (see paragraphs 8.98 to 8.146).

8.63 On this basis, we have used two different measures of indirect costs for GB DNOs in our comparisons with NIE:

(a) the total gross costs reported by GB DNOs for indirect costs minus costs attributable to non-distribution activities; and

(b) the indirect costs under *(a)* above minus all costs identified as attributable to connections activities (covering connections activities funded through connection charges as well as connection activities funded through the main price control).

8.64 For our benchmarking comparisons excluding indirect costs attributed to connections, we have made deductions to NIE's costs using an allocation factor proposed by NIE and its consultant Frontier. NIE provided us with the Excel model used in Frontier's benchmarking analysis in August 2013. This used an allocation factor of 20.3 per cent to allocate NIE's indirect costs to connections activities. This allocation was based on the proportion of NIE and NIE Powerteam staff attributed to connections work. We used the same figure of 20.3 per cent to attribute part of our estimate of NIE's indirect costs to connections. This resulted in a deduction from NIE's indirect costs of around £9 million in 2009/10.

8.65 In October 2013, NIE submitted a further report on benchmarking analysis prepared by Frontier, in response to initial analysis we had shared with NIE and the UR. This reported that NIE had undertaken additional work with Frontier to develop a bottom-up measure of the appropriate connections adjustment for 2009/10 based on detailed analysis of accounting and management information. The report says that this new analysis reveals that the indirect cost allocation to connections should be 21.7 per cent. On Frontier's revised analysis, this amounts to an attribution of around £9.6 million of indirect costs to connection activities.

8.66 For the purposes of our provisional determinations, we have not sought to update our benchmarking analysis in light of the new analysis provided by NIE. The difference between the Frontier figure of £9.6 million and our figure of £9 million is about 1 per cent of NIE's indirect costs and IMF&T costs (excluding connections). Whilst Frontier's analysis provides some additional information on the costs NIE incurs for specific connections activities, it also highlights the extent to which the attribution of connection costs is a subjective assessment with different possible allocation methodologies. In particular, for both Frontier's original and revised methods for allocations of costs to connections, a significant amount of NIE T&D overheads are allocated to connections according to the extent to which Frontier attributes NIE Powerteam's costs to connection activities. Frontier's revised allocation methods may give undue prominence to NIE Powerteam within NIE's business: the various activities carried out by NIE (eg network asset replacement, repairs and maintenance, metering activities and new connections) involve not only the costs of NIE Powerteam but also other costs (eg using staff from NIE or subcontractors). We expect to need to reconsider the allocation to connections in light of responses to our provisional determinations.

Treatment of wayleaves costs

8.67 In its original benchmarking reports for NIE in February 2011, Frontier included NIE's wayleaves costs as part of the calculation of NIE's indirect costs. Ofgem's category of indirect costs includes wayleaves costs and the publicly available cost data for the GB DNOs from the DPCR5 financial model included wayleaves costs. CEPA took the same approach in its analysis for the UR.

8.68 Frontier maintained its approach to wayleaves in an updated benchmarking analysis submitted by NIE in August 2013. However, in a report submitted by NIE in October 2013, Frontier proposed a different approach: either that wayleaves are excluded from the benchmarking analysis or that adjustments are made to NIE's wayleaves costs to normalize them. Frontier said that NIE incurred a high absolute level of way-leave costs and that this was attributable to NIE's extensive EHV/HV overhead line network. Frontier's report indicated that some of the econometric models we use are unlikely to account for the impact on costs of differences between companies in terms of the length of their EHV and HV overhead line networks.

8.69 We did not seek to exclude wayleaves costs or to make an adjustment for NIE's relatively high wayleave costs as part of our benchmarking analysis. This is due to a number of factors:

(a) We do not consider it appropriate to exclude automatically a category of costs from our benchmarking analysis on the basis that NIE has relatively high costs in that category due to factors that are not fully taken into account in the econometric models. Our approach to benchmarking analysis is based on relatively aggregated econometric models and it is inevitable that they will not take full account of all such effects.

(b) Whilst Frontier argued that our benchmarking analysis might be unfavourable to NIE in relation to wayleaves, other aspects of the analysis might be favourable. For instance, the UR argued that the econometric models that we used were favourable to NIE because they did not take enough account of NIE's relatively limited requirements for tree-cutting expenditure.

(c) We accept that it might be possible to develop a method for normalization adjustments for wayleaves, but this would require considerable further analysis. Our experience from our work on wage adjustments is that seeking to make normalization adjustments can be a resource-intensive process. Given the small scale of

the differences in wayleave costs between NIE and other companies, relative to NIE's total indirect costs, we did not consider it proportionate to develop work on potential normalization adjustments.

(d) Finally, we cannot exclude the possibility that NIE's relatively high historical way-leave costs reflect, to some degree, the fact that these costs have been subject to full cost pass-through and NIE has not been financially exposed to the level of its wayleave costs.

Econometric model specification and estimation method for indirect costs

8.70 We have used econometric models to compare cost data from NIE and the 14 GB DNOs. We have drawn on the approach taken by Frontier and CEPA and also considered a slightly wider set of models.

8.71 Our data for GB DNOs covers the years 2009/10, 2010/11 and 2011/12. We have data for NIE on a consistent basis only for 2009/10. Nonetheless, we use the data for the three-year period as it brings more data to bear on the estimation of the coefficient on the explanatory factor. We include time dummy variables in our model specification to make some allowances for industry-level changes in costs from one year to the next (relative to the RPI, which we use to deflate cost data before comparing costs).

8.72 We used relatively simple models with a single explanatory factor intended to take some account of differences in the scale of each company's distribution activities. In particular, we considered models that include the following explanatory factors:

(a) a composite scale variable used by Ofgem for its DPCR4 price control review: for each company, this is a weighted average of the company's number of connected customers, length of network and units of electricity distributed. We call this CSV(1); and

(b) a different composite scale variable that Ofgem used for some if its analysis during its DPCR5 price control review, which is based on a weighted average of an estimate the modern equivalent asset value (MEAV) of the company's distribution system and an aggregated measure of the direct costs of the company's capex programme. We call this CSV(2).

8.73 These variables are defined in more detail in Appendix 8.5.

8.74 The benchmarking analysis carried out by Frontier focused on models with the DPCR4 composite scale variable we label CSV(1) above. Frontier had considered whether it was possible to use the more complex and detailed types of models used by Ofgem for its DPCR5 price control review but found that this was not practical.

8.75 CEPA carried out benchmarking analysis for models with both explanatory factors CSV(1) and CSV(2) above.

8.76 We sought to replicate the model specification of Frontier and CEPA. In each case, the dependent variable in the regression analysis is indirect costs. In line with the sensitivity analysis presented by Frontier and CEPA, we estimated versions of these models in which cost and explanatory factor data are converted to logs before model estimation and versions in which they are not.

8.77 In addition, we used a different type of model which compares measures of indirect costs *per connected customer*, rather than comparing indirect costs. We specified two such models:

(a) One model includes a constant and time dummy variables but no explanatory factor. This model effectively provides a simple comparison of average costs per customer. Whilst perhaps not the most suitable model to use, it provides a useful reference point and comparison against the more complicated models. For example, a comparison with the results from this model can help illustrate the extent to which more complicated models make allowances for differences between companies besides differences in the number of connected customers on the network.

(b) The other model includes an explanatory factor specified as natural logarithm of the average length of the company's network per customer. For this model, we use the natural logarithm of the cost per customer as the dependent variable.

8.78 The six models we have considered are summarised in Table 8.2.

TABLE 8.2 **Model descriptions**

Model	*Description*
M1	Regression of cost on CSV(1) and time dummy variables
M2	Regression of cost on CSV(2) and time dummy variables
M3	Regression of cost per customer on time dummy variables
M4	Regression of ln(cost) on ln(CSV(1)) and time dummy variables
M5	Regression of ln(cost) on ln(CSV(2)) and time dummy variables
M6	Regression of ln(cost per customer) on ln(network length per customer) and time dummy variables

Source: CC.

8.79 The simple econometric models we have used cannot take full account of all differences between electricity distribution companies in the UK that affect their costs. However, they can provide an approximation of the level of costs of a company with a given scale of activity (as proxied by the explanatory factor in model) if it were reasonably efficient.

8.80 In its Statement of Case (p188), NIE said that it was not reasonable to apply a downward wage adjustment to NIE's costs for the purposes of comparison with GB DNOs without taking account of other significant differences between regions. It said that taking account of the sparse nature of NIE's network was likely to offset the regional wage adjustment. However, NIE has not substantiated this point. In any event, the models we considered include models which take some account of differences in sparsity of network. For instance, the explanatory factor in model M6 estimates the impact on indirect costs per customer of differences between companies in the length of network per customer. All the other models apart from model M3 take some account of differences between companies relating to sparsity.

Choice of benchmark used to estimate 'efficient' costs for NIE

8.81 The UR proposed cost reductions for NIE that would bring its costs in line with estimates from its model for a company of NIE's scale if it were at the 'upper quartile' of performance in the model. The use of the upper quartile follows Ofgem's approach.

8.82 The term upper quartile is somewhat ambiguous. We found that Excel and the statistics package Stata used different methods to calculate the upper quartile of a discrete distribution. Further, we found it hard to convey what is meant by the concept of upper quartile efficiency. We prefer the use of a benchmark that can be defined by reference to the benchmarking results for one of the companies in the sample.

8.83 We provisionally decided to report estimates—derived from our econometric models—of the costs that NIE would incur if it were as 'efficient' as the company ranked fifth out of 15 companies. We do not consider it reliable to view the company ranked first in the sample as an achievable benchmark for efficient costs: the results for such a company may be particularly influenced by data error and circumstances that are not representative across DNOs in the UK.

8.84 Frontier, in a report submitted to us by NIE, said that a benchmark based on the fifth company was prudent and reasonable. Frontier continued: 'In any event, given the clustering of DNO performance that we have typically found in efficiency analysis similar to that considered here, there is unlikely to be a substantial difference between estimated efficient costs as measured on the 4.5th rank and 5th rank.'

8.85 In contrast, the UR said it was concerned that a benchmark based on the fifth-ranked company was insufficiently ambitious. The UR considered the fourth-ranked company a more appropriate benchmark than the fifth-ranked company. We do not share the UR's view, particularly in light of the risk that the econometric models we have used do not fully account for all the differences between companies that affect their costs.

Results from cost benchmarking comparisons

8.86 We can use the results from our econometric models to make an estimate of the relative costs of each company that takes account of some of the differences between them—specifically, the differences reflected in the explanatory factors used in the model. For instance, model M6 provides an estimate of the impact on cost per connected customer of differences in length of network per connected customer. Similarly, our wage adjustments allow us to take account of estimates of the impact of regional differences in wages across the UK.

8.87 If we attribute all cost differences between companies that are not explained by the explanatory factors in our econometric models (or our wage adjustments) to efficiency differences, we can produce a ranking of each company in terms of its relative efficiency in the sample. A rank of 1 would represent the company with the lowest level of costs relative to the level of costs predicted for it by the econometric model (after the application of any wage adjustments).

8.88 We can also produce an efficiency 'score' for each company. As stated above, we want to use the company ranked fifth as our cost benchmark. We calculated an efficiency score for NIE by dividing our measure of NIE's costs in 2009/10 by the level of costs that we estimated from the model for NIE if it were as 'efficient' as the company ranked fifth in our sample of 15 companies.

8.89 In the results below, we report the rank and score for NIE on this basis. Appendix 8.5 provides more information on how we calculate the rank and score.

8.90 The concepts of efficiency rank and score used here need to be interpreted with caution and not taken out of context. They relate to efficiency under a hypothetical assumption that our modelling approach allows us to isolate accurately the impact of all differences between companies, aside from efficiency, that affects their costs. That is not the case. The estimated impacts of each explanatory factor can only provide an approximation of the way that that factor affects companies' costs. Further, the econometric models we have used do not take account of all possible differences between companies that affect their costs.

8.91 These considerations are some of the reasons why we propose to set a cost allowance for NIE on the basis of the company ranked fifth in the sample. We consider it unlikely that the company ranked first is as efficient—and its level of costs as achievable—as a naive interpretation of the model might suggest.

8.92 We consider that the cost benchmarks we have derived from the econometric models provide a reasonable basis on which to set a cost allowance for NIE within the context of a system of RAB-based incentive regulation. We do not consider them sufficient to prove whether or not NIE was efficient in 2009/10.

8.93 With these caveats in mind, we provide results from our benchmarking analysis in terms of the efficiency score and rank of NIE. Tables 8.3 to 8.6 show results for each of our six econometric model specifications and for four different approaches to the wage adjustment applied to cost data before model estimation (including no adjustment). We report results for indirect costs only and for comparisons of indirect costs and IMF&T costs. We also produce results with and without adjustments to exclude indirect costs attributed to connections activities.

TABLE 8.3 **Comparisons of indirect costs excluding connections**

Wage adjustment	*M1* Score %	*M1* Rank	*M2* Score %	*M2* Rank	*M3* Score %	*M3* Rank	*M4* Score %	*M4* Rank	*M5* Score %	*M5* Rank	*M6* Score %	*M6* Rank
None	104	6	100	5	167	13	107	7	100	5	106	8
WA1	105	8	103	6	179	13	110	9	103	7	110	9
WA2	108	9	106	7	181	13	110	10	106	7	111	9
WA3	109	8	105	7	187	13	114	10	105	7	105	7

Source: CC analysis.

TABLE 8.4 **Comparisons of indirect costs and IMF&T costs, excluding connections**

Wage adjustment	*M1* Score %	*M1* Rank	*M2* Score %	*M2* Rank	*M3* Score %	*M3* Rank	*M4* Score %	*M4* Rank	*M5* Score %	*M5* Rank	*M6* Score %	*M6* Rank
None	99	2	94	2	145	13	99	1	94	2	102	6
WA1	101	6	99	4	151	13	101	7	98	4	104	6
WA2	100	5	98	4	154	13	100	7	98	3	102	7
WA3	99	4	97	4	150	13	100	5	98	3	97	4

Source: CC analysis.

TABLE 8.5 **Comparisons of indirect costs including connections**

Wage adjustment	*M1* Score %	*M1* Rank	*M2* Score %	*M2* Rank	*M3* Score %	*M3* Rank	*M4* Score %	*M4* Rank	*M5* Score %	*M5* Rank	*M6* Score %	*M6* Rank
None	117	9	109	7	161	14	118	9	107	7	118	10
WA1	119	9	110	7	174	14	122	10	112	7	121	10
WA2	119	9	112	8	181	15	121	9	111	8	125	10
WA3	114	10	111	8	196	15	117	10	112	8	113	10

Source: CC analysis.

TABLE 8.6 **Comparisons of indirect costs and IMF&T costs including connections**

Wage adjustment	*M1* Score %	*M1* Rank	*M2* Score %	*M2* Rank	*M3* Score %	*M3* Rank	*M4* Score %	*M4* Rank	*M5* Score %	*M5* Rank	*M6* Score %	*M6* Rank
None	104	7	100	5	157	14	104	7	99	4	109	7
WA1	108	8	102	7	165	14	108	8	102	6	112	10
WA2	106	8	104	7	167	14	106	8	103	6	109	9
WA3	104	7	100	6	167	14	104	9	101	6	101	6

Source: CC analysis.

8.94 We explain under step *(c)* below how we have set a provisional cost allowance for NIE, in light of our analysis, in the next section. Here we make a few brief observations on the results.

8.95 Including the costs for IMF&T in the benchmarking tends to improve NIE's relative position compared with the comparisons of indirect costs only.

8.96 Excluding indirect costs attributed to connections from the benchmarking analysis tends to improve NIE's relative position compared with the comparisons which do not involve an adjustment to exclude indirect costs attributed to connections.

8.97 The impact of the wage adjustments in the results of the benchmarking analysis is lower than one might have expected in view of the scale of the wage adjustments that we make (see Appendix 8.4 for information on the scale of adjustments). The disaggregated regional mean wage adjustments (ie WA1 and WA2, the adjustments that take greater account of NIE's labour force breakdown) result in NIE being further above the benchmark than when there is no wage adjustment. The simple mean regional wage adjustment (WA3) has an ambiguous effect compared with no regional wage adjustment; sometimes WA3 decreases NIE's score against the benchmark and sometimes it increases it. Even though the wage adjustment will always increase NIE's benchmarked costs, it does not worsen NIE's performance by a corresponding amount. The wage adjustment affects benchmarked costs of other companies too and has an impact on the coefficient (or relationship) estimated by the econometric model between costs and the explanatory factor in the model.

Step (c): assessment of benchmarked costs for price control period

8.98 This subsection provides our assessment of an allowance for NIE's costs using the results from the benchmarking analysis. It is structured as follows:

(a) We explain why we have placed more weight on the results from the benchmarking analysis for indirect costs and IMF&T costs taken together, rather than the results for indirect costs only (paragraphs 8.99 to 8.115).

(b) We explain why we have given more weight to the results from the benchmarking analysis that excludes indirect costs attributed to connections (paragraphs 8.116 to 8.120).

(c) We explain which of the alternative wage adjustment methods we have placed most weight on (paragraphs 8.121 to 8.123).

(d) We explain which of the alternative econometric models we have placed most weight on (paragraphs 8.124 to 8.134).

(e) We draw on the results from the benchmarking analysis to propose an allowance for NIE's indirect and IMF&T costs, excluding indirect costs attributable to connections (paragraphs 8.135 to 8.138).

(f) We describe an adjustment to that allowance which reflects an estimate of the indirect costs related to connections that NIE will need to recover through its revenue control, rather than connection charges (paragraphs 8.139 to 8.145).

(g) Finally, we provide our provisional determination for an annual allowance for NIE's indirect and IMF&T costs (before productivity and RPE adjustments) (paragraph 8.146).

Inclusion of IMF&T costs in benchmarking analysis

8.99 We have reported results from benchmarking analysis for indirect costs only and for the aggregation of indirect costs and IMF&T costs. The results differ significantly.

8.100 Both NIE and the UR made submissions on which type of benchmarking analysis is most appropriate for our inquiry. NIE's submissions argued that the analysis including IMF&T costs was most appropriate. The UR argued that the analysis excluding IMF&T costs were more appropriate.

8.101 We consider the analysis including both indirect and IMF&T costs most relevant and useful and place most weight on these in determining an allowance for NIE. The main reasons for this are as follows:

(a) This approach allows us to bring systematic benchmarking analysis using GB DNO data to bear not only on indirect costs but also IMF&T costs. This is an important consideration given our view of the benefits of benchmarking analysis as part of cost assessment within a system of RAB-based incentive regulation.

(b) Taking indirect cost and IMF&T costs together in a single analysis helps to reduce the vulnerabilities of the benchmarking analysis to differences in cost allocation between these categories.

(c) Whilst we accept that the explanatory factors in the econometric models may not fully and properly take account of all differences between companies that affect their costs, we consider that these deficiencies are shared by the models of indirect costs only. We do not agree with the view that the models of indirect costs only are robust and the models of indirect and IMF&T costs are not.

8.102 NIE's consultants made similar points.

8.103 We summarize below the alternative view presented by the UR and our response to it.

8.104 The UR raises two different types of concern with including IMF&T costs in the benchmarking analysis:

(a) The UR is concerned that the estimates of NIE's IMF&T costs that are used in our analysis are under-reported and that NIE's actual costs in their expenditure categories were higher.

(b) The UR does not consider it appropriate to include IMF&T costs in the types of econometric models that we use.

8.105 On the first point, the UR has not provided alternative figures but rather raised general concerns about the data provided by NIE. We accept that there is some risk that the cost estimates provided by NIE and its consultants may understate NIE's costs. The methods used by Frontier, to the extent that we rely on them, seem reasonable but there is room for discretion and subjectivity in the cost allocations.

8.106 The UR told us that it believed that the costs included by Frontier for inspections, faults, maintenance and tree cutting were for a smaller scope of work than that reported to Ofgem under these categorizations. The UR said that Frontier had only considered the costs that were expensed under some of these headings.

8.107 The UR also raised concerns about inconsistencies in the data that NIE provided in relation to repairs and maintenance costs. The UR referred to differences in NIE's 'opex repairs and maintenance' for 2009/10 between its BPQ response, the R&M costs in the Frontier analysis and a submission in response to questions that we had asked on potential changes in NIE's capitalization practices. In contrast to the UR, we do take the view that the costs in these separate submissions should match. For example, the costs covered in Frontier's benchmarking analysis include capitalized costs falling under the relevant Ofgem categories for network operating costs; these costs would not be reported under repairs and maintenance in NIE's BPQ response on opex. Further, we have not identified large discrepancies between NIE's BPQ response and the more recent submission on repairs and maintenance. NIE submitted data on its repairs and maintenance costs in response to questions that we had asked on potential changes in NIE's capitalization practices. These provide a figure of £9.7 million for 2009/10 for repairs and maintenance expenditure that is reported under operating expenditure rather than capitalized. The figure reported under repairs and maintenance in NIE's BPQ response on opex is £10 million.

8.108 We consider two further factors relevant in terms of concerns about the IMF&T costs for NIE:

(a) Our use of benchmarking results from NIE and 14 GB DNOs means that we place considerable weight on the costs of other companies, which helps to mitigate (though not completely eliminate) concerns about NIE's data.

(b) The impact on our cost assessment of NIE underreporting costs is ambiguous and quite possibly detrimental to NIE and beneficial to consumers. The impact of NIE's costs on the estimated coefficients from the econometric models is hard to predict in advance. But if we take account of NIE's historical costs alongside the costs from the benchmarking, a lower figure for NIE's reported costs could reduce the allowance that we choose to set.

8.109 We now consider the UR's points on the econometric model specifications. The UR argued that the econometric models we specified (M1 to M6) did not give a sufficiently robust explanation of differences in IMF&T cost between DNOs. The UR said that IMF&T costs were partly a function of the size of a network (which was captured to some degree by our econometric models) but also heavily influenced by factors like technical configuration, standards, levels of historical investment, age and current service quality. The UR argued that these things meant that two networks of the same scale might require dramatically different volumes of inspection, maintenance, fault repair and tree cutting in any given period.

8.110 We do not consider the econometric models we have used for indirect costs to be unsuitable for IMF&T costs. These models include factors that we expect to be an important driver of IMF&T costs, particularly the inspections, maintenance and faults elements (eg length of network and number of connected customers).

8.111 These may not take account of all possible factors that affect companies' costs but that criticism also applies to the indirect costs models. For instance, as discussed under step *(b)* above, NIE argued that its wayleave costs were relatively high because of the relative extent of its EHV and HV overhead line networks but this is not fully captured in the econometric models that we have used.

8.112 The UR sought to illustrate its concerns with including IMF&T costs in the econometric benchmarking analysis by comparing results from that analysis with BPI's separate assessment of NIE's tree-cutting expenditure which formed part of BPI's assessment of NIE's capex proposals (see Section 9). The UR argued that the results from the econometric analysis costs indicated that NIE was relatively efficient in IMF&T costs compared with GB DNOs but that this contradicted the separate analysis of NIE's tree-cutting costs carried out by BPI, which found NIE's forecast tree-cutting costs to be too high.

8.113 However, we were not persuaded by the argument made by the UR. The econometric analysis we have carried out compares NIE's historical costs with the historical costs of GB DNOs. In contrast, BPI's assessment concerned NIE's forecast capex for the RP5 price control period. NIE's forecast capex on tree cutting is substantially higher than NIE's 2009/10 expenditure on tree cutting.

8.114 NIE's capex forecast included £33.25 million over the RP5 period in respect of capitalized tree-cutting costs (including indirect costs). BPI recommended the exclusion of around £3.4 million of tree-cutting costs from NIE's forecast expenditure,[4] which produces an implied capex allowance for tree cutting of £29.8 million. If BPI's allowance for tree-cutting costs were spread evenly over a five-year period, this would equate to around £6 million per year. The capitalized

[4] From projects D7; D8; D9.

elements of NIE’s tree-cutting costs in 2009/10 were around £5.1 million (including indirect costs attributed to tree cutting). The impact of BPI’s assessment is to reduce the extent to which the forecast capitalized tree-cutting costs for NIE are above NIE’s 2009/10 tree-cutting costs.

8.115 At future price control reviews for NIE it may be possible to carry out more granular and detailed benchmarking analysis for IMF&T costs which takes these costs (or elements of them) separately from indirect costs and uses different econometric models in each case. However, this option was not available to us. The UR accepted that whilst more granular econometric benchmarking might be desirable, it was not possible for our inquiry.

Exclusion of costs attributed to connections

8.116 We produced results for models that include indirect costs attributed to connections activities and models that exclude direct costs attributed to connections activities.

8.117 We considered on which to place most weight for our cost assessment. We gave attention to three main issues:

(a) A large element of NIE’s connection costs are funded by customer contributions and should not be funded as part of the expenditure allowance set as part of our determination. Excluding connection costs allows a better alignment between the costs used for benchmarking analysis and the costs for which we want to make an allowance as part of our cost assessment.

(b) Excluding connection costs helps to address a possible vulnerability of the econometric benchmarking analysis. The econometric models we have used are not well suited to taking account of variations between different companies in the amount of connection work that each company is required to carry out in any financial year. The explanatory variables in these models capture differences in

the scale of companies' networks but not differences in the amount of new network connection activity. This point is particularly important because there is greater scope for competitive third parties to carry out connections in GB than Northern Ireland, which will tend to reduce the role of GB DNOs in connection work. It is also important in view of the scale of connection activity—NIE estimated that it was about 20 per cent of indirect costs. The differences in NIE's performance in the benchmarking models including and excluding connections could be explained by the differences in the amount of connection work.

(c) If connection costs are excluded, the benchmarking results may be adversely influenced by differences between companies, or over time, in the methods used to allocate indirect costs between connection activities and other activities. Carrying out benchmarking analysis without an adjustment to exclude connection costs tackles this concern.

8.118 In view of a combination of *(a)* and *(b)*, we place more weight on the benchmarking analysis that compared indirect costs and IMF&T costs excluding costs attributable to connections.

8.119 On its own we would not necessarily consider point *(b)* decisive. As we have discussed elsewhere in relation to wayleave costs (see paragraphs 8.67 to 8.69) and IMF&T costs (see paragraphs 8.99 to 8.115), we are reluctant to shrink the scope of benchmarking analysis to address claims about the limitations in the econometric models.

8.120 We have concerns in relation to point *(c)*. We sought to address these concerns to some degree by also considering cost benchmarks for 2010/11 and 2011/12. This helps to reduce the dependency of our cost assessment on the cost allocations in

2009/10, which was the first year following significant changes to Ofgem's cost reporting rules in relation to connections.

Discussion of wage adjustments

8.121 We place more weight on benchmarking results that do involve a regional wage adjustment. We note, however, that in some cases this has relatively limited effects.

8.122 Our preferred wage adjustment method is WA2. This strikes a balance between including occupational categories that are relevant to the activities of NIE and GB DNOs and avoiding the risks of data error from a small sample size.

8.123 We have also taken account of the concern raised by the UR that the more granular the regional wage adjustment measures are, the greater the risk that the adjustments used to normalize each DNO's costs are influenced by the wages actually paid by the DNO in that region. This could mean that any inefficiently high wages by a particular DNO could be attributed to regional conditions by the wage adjustment method.

Discussion of alternative econometric models

8.124 We placed most weight on the results from Models M4 and M6.

8.125 Model M4 is a version of M1 except that the dependent variable and explanatory factors are converted to natural logarithms before model estimation. Both CEPA and Frontier used Models M4 and M1 in their analysis. These models reflect a model used by Ofgem in its DPCR4 price control review.

8.126 We consider the logarithmic version a better model of how the composite scale variable is likely to affect costs (as an approximation). Model M4 implies a proportionate relationship between the dependent variable and the composite scale variable (eg a 1 per cent increase in the composite scale variable is estimated to increase indirect costs by 0.5 per cent). In contrast, Model M1 implies a relationship in which the impact of the composite scale variable on costs is the same for all values of the composite scale variable (eg a 1 unit increase in the composite scale variable is estimated to increase indirect costs by £0.5 million regardless of whether the scale of the company, as measured by the composite scale variable, is high or low).

8.127 Models M1 and M4 take account of the number of connected customers, network length and the amount of electricity transmitted. However, these models impose hard-coded weights on each of these elements rather than using the available data to estimate the impact of each of these factors on costs. Due to the small sample size and nature of the data, we consider it unlikely to be possible to specify an alternative version of Model M4 that enables us to make accurate estimates of the effects of each of these three factors on costs. Nonetheless, the results of Models M1 and M4 (and also M2 and M5) will depend on the weight attached to each of the elements in the composite scale variable and we do not have grounds to believe that these are the most appropriate weights.

8.128 Further, the inclusion of the units of electricity distribution in Models M1 and M4 may worsen rather than improve the accuracy of these models. A variation in the amount of electricity distributed by a DNO seems unlikely to have a large impact on its indirect costs and IMF&T costs. Differences between companies in the volume of electricity distribution may provide a proxy for other differences (eg the scale and capacity of network infrastructure) that do affect these costs and which are not fully captured in differences in network length of number of customers. However, there is year-to-year volatility in the volume of electricity distributed. This volatility may have little impact on indirect and IMF&T costs but could adversely affect the model's results.

8.129 Model M6 compares costs per connected customer between companies, and produces an estimate of the impact of variations in network length per connected customer on costs per connected customer.

8.130 The specification of Model M6 corresponds to a model used in the past by Ofwat as part of its relative efficiency analysis of water companies' opex.[5] That model specifically concerned expenditure on companies' water distribution networks. In Ofwat's model, the dependent variable was the natural logarithm of distribution network expenditure per connected property, and the explanatory factor was the natural logarithm of the length of water mains per connected property.

8.131 We consider that Model M6 is another reasonable model that we should look at alongside Model M4. It also tackles some of the shortcomings of Model M4:

(a) It does not treat the volume of electricity distributed as an important determinant of variations in costs between companies.

(b) It does not rely on a composite scale variable that requires the external specification of weights to different explanatory factors.

(c) Because the dependent variable is cost per customer, rather than total costs, M6 is less prone to the statistical problem of heteroscedasticity.

8.132 Against this, a possible disadvantage of Model M6 is that whilst it allows for differences between companies in terms of the length of network (per customer), it does not allow for economies of scale with respect to the number of connected customers.

8.133 We placed less weight on Models M2 and M5. These models use a composite scale variable that is calculated as the weighted average of an estimate of the MEAV of each company's network and a measure of its network investment expenditure. We

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[5] For example, see Ofwat 'Relative efficiency assessment 2008-09 – supporting information', December 2009.

included this model in our presentation of results because it was used by CEPA in its analysis for the UR. We have some concerns about using cost data as an explanatory factor. For example, any inefficiency or excessiveness in a particular company's network investment expenditure programme would indicate, in these models, that the company has higher requirements for indirect costs and IMF&T costs. We also have greater concerns about the accuracy of the MEAV estimates for the companies in the sample than about the accuracy of the explanatory factor data used for the other models. In addition, the data we used in our analysis of these models was not fully updated for the years 2010/11 and 2011/12.[6]

8.134 Finally, Model M3 is based on a simple comparison of costs per connected customer. It makes no allowances for other differences between companies. We do not consider this model suitable for setting an allowance for NIE.

Cost benchmarks and provisional determination of allowance

8.135 Based on the discussion above, our preferred approach is to set a cost allowance for NIE covering both indirect costs and IMF&T costs, using benchmarking analysis excluding connection costs.

8.136 Table 8.7 shows, for each econometric model and wage adjustment method, the predicted costs for NIE from our analysis assuming it were as efficient as the fifth-ranked company. The table also shows our estimate of NIE's costs in 2009/10.

[6] We estimated results for these models using cost data for the period 2009/10 to 2011/12 but with the same explanatory factor data for 2010/11 and 2011/12 as for 2009/10 (we used the data provided in CEPA's analysis which did not run beyond 2009/10). This was an approximation to avoid the need to request and process a large amount of additional data from Ofgem; this would have been disproportionate given the other limitations of these models.

TABLE 8.7 **Cost benchmarks for 2009/10 for indirect and IMF&T costs (excluding costs attributed to connections)**

£ million

	WA0	*WA1*	*WA2*	*WA3*
NIE's 2009/10 indirect + IMFT cost	52.3			
Predicted cost M1	52.7	51.7	52.3	52.6
Predicted cost M2	55.6	53.1	53.4	54.2
Predicted cost M3	36.0	34.6	34.0	34.8
Predicted cost M4	53.0	51.6	52.1	52.3
Predicted cost M5	55.9	53.1	53.3	53.4
Predicted cost M6	51.5	50.4	51.3	54.0

Source: CC analysis.

8.137 In light of the considerations set out above, we propose an allowance of £51.5 million for NIE's indirect costs and IMF&T costs, excluding indirect costs attributed to connections. We have placed most weight on the results in Table 8.7 for Models M1 and M6 and for the wage adjustment method WA2.

8.138 We identified concerns above that our results might be unduly influenced by cost allocations to connections made by the GB DNOs in 2009/10 which was the first year of the new regulatory reporting rules introduced by Ofgem as part of its DPCR5 price control review. We considered, in particular, whether the differences in NIE's performance in the models excluding connection costs (where NIE performs relatively well) and models including connection costs (where NIE performs less well) might reflect inconsistencies or inaccuracies with the GB DNOs cost allocations in 2009/10. To help tackle this concern we also looked at versions of the cost benchmarks above for the financial years 2010/11 and 2011/12. Our results for 2010/11 from this analysis are set out in Table 8.8. Because our data does not include costs for NIE for 2010/11 the econometric results for this year are not directly comparable with those for 2009/10. Nonetheless, the results do not support the concern we had that specific features of the 2009/10 GB DNO cost allocations to connections may distort the results and overstates NIE's relative performance in the benchmarking analysis.

TABLE 8.8 **Cost benchmarks for 2010/11 for indirect and IMF&T costs (excluding costs attributed to connections**

				£ million
	WA0	*WA1*	*WA2*	*WA3*
Predicted cost M1	55.8	53.1	55.7	56.0
Predicted cost M2	56.7	53.4	56.7	55.8
Predicted cost M3	38.5	37.9	36.4	36.6
Predicted cost M4	55.6	53.1	52.3	53.8
Predicted cost M5	56.0	53.5	53.5	53.5
Predicted cost M6	55.1	53.7	52.0	56.7

Source: CC analysis.

Adjustment for connection costs to be funded through price control

8.139 The allowance above is for NIE's indirect costs and IMF&T costs excluding indirect costs attributed to connections.

8.140 NIE makes separate connection charges to customers and we propose that revenues from these connection charges are outside the scope of the restriction on NIE's maximum regulated revenue. We would expect the majority of NIE's indirect costs attributed to connections to be funded through connection charges. However, there may be a relatively small element of costs that are not. The main areas of such costs we have identified are: elements of network reinforcement costs (system costs) that are not 100 per cent recoverable via connection charges under NIE's connection charging policy, and, perhaps, indirect costs incurred in the preparation of quotes which are not charged for or accepted.

8.141 We asked NIE to provide further information about its allocation of indirect costs to connection activities and the extent to which these costs are recovered from connection charges. More specifically, we asked NIE for an estimate of the value (£ million) of the NIE indirect costs in 2009/10 that is attributable to the indirect costs of connection activities which were recovered from connection charges or customer contributions paid to NIE. NIE was not able to provide such an estimate. It said that the main reason for this was that it did not collect its cost data on the same basis as used for regulatory reporting by the GB DNOs and that a split of connection costs recovered from customers between direct and indirect costs was not readily available.

8.142 The fact that NIE does not currently report costs under the Ofgem regulatory reporting framework does not mean that it was not possible for NIE to provide the estimate we had sought. That fact has not prevented NIE and its consultants from making a series of estimates of its costs based on the Ofgem RIGs definitions for the purposes of NIE's submissions on its benchmarking analysis. For example, the various reports and spreadsheets prepared by Frontier for the purposes of benchmarking analysis include: *(a)* a 'cost mapping' or allocation of NIE Powerteam's costs between direct and indirect costs; *(b)* an estimate of the elements of NIE's costs that fall under the Ofgem cost categories for 'network operating costs' and an adjustment to exclude indirect costs from that estimate; and *(c)* an estimate of the elements of NIE's indirect costs that are attributed to connection activities.

8.143 In the absence of the information we sought from NIE, we used other information available to make an approximate adjustment to our proposed allowance for NIE's indirect and IMF&T costs to provide for indirect costs related to connections that are not covered by connection charges. In particular, we considered costs arising from system reinforcement work that is attributed to connections but not covered by connection charges.

8.144 Frontier reported that very little connection activity by NIE was associated with system reinforcement work, stating that in 2009/10 only 2.3 per cent of demand connections were associated with wider system work. NIE subsequently told us that about 4.3 per cent of total connections by value was recorded as system improvement or reinforcement work and that none of the costs associated with system improvement or reinforcement work was presently recovered from connecting parties.

8.145 We include in our proposed allowance for NIE's indirect costs an additional £0.4 million for indirect costs for connection activities not covered by connection charges. We calculated this by multiplying the element of NIE's indirect costs that we treated as attributable to connections for the purposes of our benchmarking analysis (around £9 million) by the proportion of NIE's connections activity, by value, that NIE records as system jobs (4.3 per cent).

Provisional determination

8.146 Our proposed annual allowance for NIE's indirect costs and IMF&T costs (before productivity and RPE adjustments) is £51.9 million. This includes the figure of £51.5 million that we determined from the benchmarking analysis and an adjustment of £0.4 million for indirect costs attributed to connections that need to be recovered through NIE's maximum regulated revenue rather than through connection charges.

9. Core network investment

9.1 This section considers NIE's core network investment allowance for RP5,[1] ie the core network investment expenditure that we think NIE would incur if it operated and invested efficiently, given the services (and outputs) it will provide and the obligations that it will face (see paragraph 7.1).

9.2 The great majority of investment covered in this section concerns capex on asset replacement and refurbishment work required to maintain the safety and operation of NIE's distribution and transmission systems (eg replacement in light of the age and condition of assets).

9.3 In addition, some expenditure also relates to: the capitalized costs associated with actions by NIE to resolve faults and emergency situations on its network; investment to increase capacity of NIE's distribution system to accommodate additional demands on it (load-related expenditure); a small amount of IT; and projects to improve the quality of service of particular groups of customers (for example, rural customers).

9.4 Core network investment excludes expenditure on New Connections, Metering, Non-network capex and investments previously agreed by the UR and NIE as being Fund 3 projects. We consider such expenditure in Section 10.

9.5 We have not considered RPEs as a lump sum to be added to the capex allowance (as the UR did in its Final Determination). Instead, we have forecast the percentage adjustment which should be made to our cost allowances in respect of RPEs and Productivity; our provisional decision in this area can be found in Section 11.

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[1] We would note that all capex values quoted in this section are in 2009/10 prices.

9.6 This section is structured as follows:

(a) We explain the background to core network investment and our approach to setting an allowance in this area.

(b) We summarize the conclusions of our engineering consultants' review of NIE's core network investment plan.

(c) We provide an additional review of three of NIE's projects.

(d) We make a forecast for non-recoverable alterations and make two additional adjustments to BPI's recommended core network investment allowance.

(e) We summarize the effect of the adjustments in *(c)* and *(d)* on our core network investment allowance.

(f) We make a forecast of the direct-only costs our allowance.

(g) We consider what adjustments to our allowance are required for different time periods.

Background and our approach to core network investment

9.7 NIE submitted a core network investment request of £526.4 million. This was for a five-year period, April 2012 to March 2017. Table 9.1 shows how this reconciles to the request included in NIE's Statement of Case.

TABLE 9.1 **NIE's core network investment request**

	£m
Core request per NIE SoC	607.3
Less: RPEs	–37.5
Less: projects now agreed with the UR as Fund 3	–43.4
Core network investment defined by CC	526.4

Source: NIE Statement of Case, pp413 & 414; CC analysis.

Note: An additional £0.9 million was added to project T36. This represents the difference between the total in the Statement of Case (£606.4) and the above table (£607.3 million).

9.8 In its Final Determination, the UR awarded NIE a core network investment allowance of £335.4 million, a difference of £191 million to NIE's request of £526.4 million.

9.9 NIE's core network investment submission comprised 79 individual projects which together amounted to its request of £526.4 million. We recognized that in order to assess NIE's submission it would be necessary for us to employ engineers with specialist knowledge of electricity transmission and distribution networks.

9.10 We therefore used the Ofgem framework agreement to tender for engineering consultants. BPI was selected as a result of this tender process.

9.11 In our terms of reference for BPI we asked it to:

(a) identify the projects, and planned volumes of work, which need to be undertaken before 1 October 2017 in order to maintain services to customers, comply with applicable network design and planning standards and/or meet any other obligations;

(b) identify the projects and planned volumes of work which, whilst not necessary to maintain services to customers, comply with applicable network design and planning standards and/or meet any other obligations, and have been included in NIE's business plan for the period to 1 October 2017 with sufficient justification; and

(c) identify any projects or volumes of work within *(b)* that any reasonable electricity transmission/distribution company would undertake before 1 October 2017 because deferring or cancelling them would undoubtedly increase whole-life costs.

9.12 In addition, we asked BPI to review the unit cost forecasts that underpinned NIE's submission.

9.13 Our intention in setting the terms of reference was to be able to identify the amount of core network investment which might be appropriate for RP5 in a number of different scenarios. These included:

(a) *Setting core network investment at the minimum required level*. This would represent category *(a)* in BPI's terms of reference. We believe that this category represents an estimate of the minimum amount of core network investment which NIE would need to complete in RP5 in order to meet its obligations. It excludes investment which might be sensible to complete in order to pre-empt network problems, improve service quality or reduce network costs in the long term.

(b) *Setting core network investment to include all well justified projects.* This would represent category *(a)* plus category *(b)* in BPI's terms of reference. This estimate includes all projects which have been included by NIE with sufficient justification. It should therefore include all projects which, in BPI's judgement, it would be sensible for NIE to complete in RP5.

(c) *Setting core network investment at the minimum level but also including projects which, if not completed, would clearly increase all life costs.* This would represent category *(a)* plus category *(c)* in BPI's terms of reference. Category *(c)* is a subset of category *(b)*. Projects in this category are distinct in that, in BPI's judgement, any engineer would recommend completing these projects to avoid increasing all life costs. Setting the allowance at this level would involve excluding a number of projects (those in category *(b)*) which in BPI's judgement should be completed in RP5.

9.14 Given the limited time available to complete the review and the large number of individual projects in NIE's plan, we asked BPI to focus its detailed review on those projects where the greatest differences existed between the UR's Final Determination and NIE's request. In addition we asked BPI to review a small sample of higher value projects where the UR had granted NIE's request in full.

9.15 BPI had full access to the extensive capex submissions made to us by the parties, as well as NIE's original project submissions and the UR's responses to those submissions. This included the extensive work which had been conducted by engineering consultants on behalf of the UR (SKM) and NIE (PB Power). In addition, BPI attended a site visit to Northern Ireland.

9.16 Following the publication of its draft report BPI received written responses from both parties and held face to face meetings with both parties. These meetings enabled both the UR and NIE to identify specific areas where they considered BPI needed to re-evaluate its draft conclusions. Following the submission of additional material clarifying points made at these meetings BPI prepared the final version of its report.

BPI's report on core network investment

9.17 In this section we summarize the key findings of BPI's report and then explain how we used these findings.

BPI's recommendation

9.18 Table 9.2 shows BPI's estimate of the categories of core network investment contained in our terms of reference (see paragraphs 9.11 to 9.13 above).

TABLE 9.2 **BPI's estimate of categories A, B and C for RP5**

	£m
Category A	197.5
Category B	195.1
Category C	55.6

Source: BPI report.

9.19 In the remainder of this section we focus on BPI's recommended core network investment allowance. This was those projects in categories A and B (that is, those projects which in its judgement had been included in NIE's plan with sufficient justification to be completed in RP5).

9.20 BPI recommended a core network investment allowance for RP5 of £392.6 million. This was £133.8 million lower than NIE's submission and £57.2 million higher than the UR's Final Determination for RP5. Table 9.3 below shows some of the largest differences between BPI's core network investment recommendation and NIE's submission.

TABLE 9.3 **Largest project differences between BPI's recommendation and NIE's request**

£ million

	NIE submission	*BPI recommendation*	*Difference*
Project D56—Network Resilience ('Ice Accretion')	35.0	0	35.0
Projects D43/T40—ESQCR legislation	25.0	2.4	22.6
Project D12—Distribution Overhead Lines Fixed Costs	18.1	0	18.1
Project D48—11kV Network Performance (remote control facilities in the rural network)	9.0	0	9.0
Projects D45/T41—Capitalized Overheads	27.2	20.5	7.2
Project D49—Smart Grid	6.4	3.0	6.4
Project T14—110/33kV Transformers replacement	10.7	6.9	3.8
Projects D17/18; T21/22 Reactive / Fault & Emergency	28.5	25.1	3.4

Source: BPI report.

9.21 The differences between BPI's recommendation and NIE's request can be broadly categorized as follows:

(a) *Volumes of work.* This is where BPI has recommended that a different volume of work should be completed during RP5 than that proposed by NIE.

(i) For some projects BPI recommended a reduction in NIE's volumes of work. For example, it recommended the replacement of six 110/33 kV transformers (including one spare) rather than the eight which NIE had requested (Project T14).

(ii) For other projects BPI has recommended zero volumes. That is, it did not think that these projects were necessary (for example, Project D56—Network Resilience/Ice Accretion).

(b) *Unit costs.* This is where BPI recommended that the unit costs submitted by NIE for a project should be adjusted. BPI's report only contains one adjustment of this type: to tree-cutting costs on overhead line programmes. For these projects (D7, D8, D9) BPI accepted NIE's proposed volumes of work but proposed a 10.8 per cent reduction to the unit costs associated with the tree-cutting element of the projects.

(c) *Legislation.* NIE requested £25 million in relation to Electricity Safety, Quality & Continuity Regulations (ESQCR) legislation and £4.4 million in respect of Road and Street Works (RASW) legislation. BPI did not think that £22.6 million of NIE's ESQCR request was necessary.

(d) *Indirect costs.* Five of NIE's projects wholly comprised indirect overhead costs. These are Capitalized Overheads (D45 and T41), Distribution Overhead Fixed Lines (D12) and Design & Consultancy (D20 and T23). BPI made an allowance of £30.1 million in this category compared with NIE's request of £57.3 million.

How we used BPI's report

9.22 Following a detailed review of BPI's final report, we decided to adopt its recommendations in respect of adjustments to the planned volumes of engineering work over the period. We decided to do this because in our view planned volumes of engineering work is an area involving a substantial element of engineering judgement and we believed that BPI was in a strong position to make this judgement.

9.23 We then applied additional scrutiny to the following projects:

(a) Project D56—Network Resilience (Ice Accretion);

(b) Projects D43 and T40—ESQCR compliance; and

(c) Project D48—11 kV Network Performance.

9.24 It was also necessary for us to make a number of adjustments to BPI's recommendation. We added a forecast for non-recoverable alterations, because we have provisionally decided that non-recoverable alterations should have an ex-ante allowance rather than be treated on a pass-through basis (see Section 5). We also made adjustments in respect of RASW legislation, the project management costs for the Ballyumford switchboard (T26) and the allowance for distribution-load-related expenditure.

9.25 As explained in Section 7, we decided that it was important to make a core network investment allowance for NIE which was on a direct cost basis. We therefore considered direct and indirect costs in more detail and made a direct-only allowance.[2]

9.26 The remainder of this section is structured as follows:

(a) We consider three projects which we identified as requiring additional scrutiny. We explain any adjustments to the core network investment forecast resulting from this review.

(b) We make a forecast for non-recoverable alterations.

(c) We explain three additional adjustments which we have made to BPI's recommendation.

(d) We revise BPI's core network investment allowance in light of *(a)* to *(c)* above.

(e) We make an estimate of the direct-only costs within our core network investment allowance.

(f) We consider what adjustments may be required to our forecast in light of our provisional RP5 revenue control period.

Additional project review

9.27 We decided that there were three projects which, for the reasons specified below, required additional scrutiny. These were:

(a) Project D56—Network Resilience (Ice Accretion);

[2] We define direct and indirect costs according to Ofgem's cost reporting rules and as relied on by Frontier and PB in their analyses for NIE.

(b) Projects D43 and T40—ESQCR compliance; and

(c) Project D48—11 kV Network Performance.

9.28 We consider each in turn.

Project D56—Network Resilience

9.29 This project stood out because it had the single largest difference between NIE's core network investment submission and BPI's recommendation. It was also the single largest project difference between NIE and the UR in the UR's Final Determination.

9.30 This project was prompted by increasing concern (arising out of three events between 2001 and 2010) regarding a potentially high impact ice accretion[3] event affecting NIE's 25mm^2 conductors. The project would involve a pilot programme of replacing small section 25mm^2 conductors with 50mm^2 conductors.

9.31 NIE requested £35 million for this pilot project. It had originally submitted a claim of £127 million for RP5.

9.32 The purpose of the replacement of the smaller sized conductors is to reduce the risk and impact of an 'ice accretion' event. NIE said that the impact of such an event would be geographically isolated but could result in tens of thousands of customers being off supply for an extended time. Whilst the larger replacement conductors might still suffer damage in such an event, the degree of damage would be greatly reduced.

[3] Ice accretion on power transmission lines is caused by freezing raindrops, super-cooled cloud droplets or snowflakes on the cable surface. This phenomenon can cause significant damage to electric power transmission networks.

9.33 The UR told us that NIE had not provided any information on the planned outage impact; that it had not done anything to look at whether customers felt this was valuable or not; and that it had not done any cost benefit analysis (CBA) for a pilot project which was forecast to cost £35 million.

9.34 BPI said that ice accretion was regarded as a low probability event in the UK electricity supply industry, and that it also tends to be geographically localised. It noted that NIE did not consider the quantity of 25mm^2 conductor as having a fundamental impact on network performance in terms of average weather. BPI concluded that, because of the low probability of severe cold weather events and in particular ice accretion, it did not accept the wholesale replacement of 25mm^2 conductors would significantly improve the overall performance of the network for the majority of NIE's customers. It also concluded that the benefits of the proposed pilot programme were dubious at best and in all likelihood would provide no more information than was already available.[4]

9.35 We considered the evidence submitted by NIE and the UR as well BPI's findings. We noted that 25mm^2 conductors were being replaced anyway through NIE's conventional refurbishment and re-engineering programmes. As such this project represented a proposal to accelerate this replacement cycle due to the specific network risks identified by NIE.

9.36 NIE's project proposal was for replacement over a 15-year period. This compares with a replacement period of approximately 30 years if the project was not approved (using age-based replacement, assuming a conductor life of 70 years).

[4] BPI final report, p121—to be published.

9.37 We were concerned about the size and potential benefits of the proposed pilot project, which BPI had suggested may not provide significant amounts of additional new information. In addition, we were concerned that this was a project which, if completed over 15 years, would involve a total capital cost well in excess of £500 million. We believed that we should require strong evidence to approve a project of this size given the cost implications for consumers. At a minimum we would expect a robust CBA, customer consultation on costs and consideration of alternative approaches before a project of this scale could be approved. We judged that NIE's proposals on this project were not supported by strong evidence and as such we decided that it was appropriate to retain BPI's recommendation to reject this project for RP5.

Projects D43 and T40—ESQCR compliance

9.38 This project stood out because of the proposed phasing between RP5 and RP6 which had been recommended by BPI.

9.39 The ESQCR regulations specify safety standards and are aimed at enhancing the level of protection to the public from the dangers posed by electrical equipment. The ESQCR regulations became law in Northern Ireland in December 2012. They replace the Electricity Supply Regulations (Northern Ireland) 1991 and bring Northern Ireland in line with GB's current measure which is the ESQCR 2002 (amended in 2006 and 2009). For certain requirements the ESQCR regulations allow for a phased introduction over a period of either five or ten years. The Explanatory Memorandum to the ESQCR Regulations notes that NIE:[5] '… has applied to the Utility Regulator for extra funding to be spent over a number of years. The Regulator will keep the arrangements under review to monitor the effectiveness of the new measures and associated costs'.

[5] www.legislation.gov.uk/nisr/2012/381/pdfs/nisrem_20120381_en.pdf.

9.40 The ESQCR Regulations identify the main duty holders responsible for maintaining safety and power quality standards and continuity of supply. They impose requirements on the installation and use of electrical networks and equipment owned or operated by generators, distributors (which includes transmitters) and meter operators and the participation of suppliers in providing electricity to consumers (all 'duty holders'). NIE is one such duty holder.

9.41 In December 2012 DETI published guidance on the ESQCR Regulations (DETI Guidance).[6] The purpose of this document is to provide guidance to duty holders on their responsibilities in the Regulations and to clarify necessary actions for duty holders to demonstrate compliance with them.

9.42 Projects D43 and T40 relate to compliance with the ESQCR regulations. NIE estimated that the total cost of compliance with this legislation (which would be phased over RP5 and RP6) was £95.2 million. NIE's estimate was based on a network sampling exercise which it conducted. It requested £25 million for RP5. It said that its forecast related only to new elements, above its existing programmes, relating to compliance with new ESQCR legislation.

9.43 A split of NIE's total estimated costs of £95.2 million for RP5 and RP6 is shown in Table 9.4.

[6] www.detini.gov.uk/guidance_document_12_12_12_final_version.pdf.

TABLE 9.4 **NIE's forecast ESQCR costs for RP5 and RP6**

	£m
Asset register	0.75
Patrolling costs	3.5
Fitting safety signs, stay insulators, and anti-climbing devices on 11 kV poles over 65% of the network	9.8
2,500 km of urban LV network 50% of which will require alterations	50.0
11 kV & 33 kV alterations	17.3
Fitting safety signs on LV poles and stay insulators where appropriate	5.7
Fitting safety signs and anti-climbing devices on 33 kV & 110 kV poles	1.7
Vegetation management	4.7
Public awareness	1.8
Total (RP5 and RP6)	**95.2**

Source: NIE.

9.44 NIE proposed a split of work between RP5 and RP6 as shown below in Table 9.5.

TABLE 9.5 **NIE's forecast ESQCR costs for RP5 and RP6**

	£ million	
	RP5	*RP6*
Asset register	0.75	-
Patrolling costs	3.5	-
Compliance remedial work	18.4	66.1
Vegetation management	1.5	3.2
Public awareness	0.9	0.9
Total	**25.0**	**70.5**

Source: NIE.

9.45 NIE said that DETI's guidance required it to spread compliance work more evenly (than implied by the UR's and BPI's allowances) across the RP5 and RP6 periods: 'It is DETI's expectation that duty holders will spread workloads associated with these new requirements equally across the permitted timescales.'

9.46 The UR allowed £1.25 million in respect of additional ESQCR costs in RP5. It told us that there was significant overlap with NIE's other investment programmes. It also told us that NIE's ESQCR submission was not supported by significant detail in relation to the surveys which had been used to make NIE's forecast. The money allowed by the UR was for additional survey work and for NIE to gather additional information on the LV network in particular. The UR told us that it suspected that there would be more investment required in the LV network in particular.

9.47 BPI recommended an allowance of £2.38 million in respect of ESQCR. It believed that the £95.2 million estimate of RP5 and RP6 compliance, which was based on sampling, appeared high compared with GB networks. In addition, it said that it could not conclude if the sampling was representative of the network as a whole.[7]

9.48 BPI viewed the priority as the establishment of an asset register based on detailed survey findings to build up a clearer view of actual proposed volumes of work. Any remedial work should then be based on data collected in RP5.[8]

9.49 BPI was also concerned that economies of scope were available and might not have been fully identified by NIE. It therefore introduced a reduction to its final allowance for an asset register and patrolling costs; this was based on overhead line assets which would be visited every five years as part of NIE's routine patrolling programme.[9]

9.50 We noted that the ESQCR Regulations specify the date from which NIE (and other duty holders) must start complying with the requirements and that they allow for a phased introduction over a period of either five or ten years for certain requirements.[10] The ESQCR Regulations do not prescribe how the work done to meet the requirements by the specified start date must be allocated across the period before the start date. As noted in paragraph 9.1 above, DETI's Guidance states that it

[7] BPI final report, pp110 & 111—to be published.
[8] ibid, pp110 & 111.
[9] ibid, pp110 & 111.
[10] Regulation 2 of the ESQCR Regulations.

expects that duty holders will spread workloads associated with these new requirements equally across permitted timescales.[11]

9.51 We considered whether, despite the absence of a binding legislative requirement to complete more of this work in RP5, it might be more efficient and appropriate to allow NIE to complete additional compliance remedial work in RP5 and also comply with the expectation in DETI's Guidance that the cost be spread out over a ten-year period.

9.52 We believed that, as a complete asset register had not yet been completed, there must be considerable uncertainty regarding the eventual cost of ESQCR compliance. For this reason we found that we could not place significant weight on NIE's £95.2 million estimate of ESQCR costs for RP5 and RP6. We therefore agreed with BPI that establishing a full ESQCR asset register was the highest priority for RP5.

9.53 We also believed that considerable economies of scope must exist between ESQCR compliance and NIE's other capex programmes. We were not convinced that these economies of scope had been fully identified. In our view, once a full asset register has been completed and additional economies of scope identified the cost of this programme might be significantly different.

9.54 Nevertheless, we also recognized that, even if the final cost estimate was subject to very significant revision, it was still likely to be a large number and that BPI's recommendation would require a very significant increase of operations in this area in RP6. We believed that this was unlikely to be the most efficient way to conduct this work.

[11] www.detini.gov.uk/guidance_document_12_12_12_final_version.pdf.

9.55 We weighed up the factors set out in paragraphs 9.52 to 9.56 and on balance we judged that it would be appropriate to allocate an additional £8 million to this programme of work for RP5.

9.56 This increases the ESQCR allowance for RP5 from £2.38 million to £10.38 million.

Project D48—11 kV Network Performance

9.57 This project stood out because it concerned an investment which was targeted at improving service quality to a relatively small group of rural consumers.

9.58 NIE requested £9.0 million for this project, but both the UR and BPI made no allowance for it. The aim of this project is to improve the quality of service for rural customers by reducing the time to restore supplies after faults. This is achieved through the installation of remote control facilities. These can isolate the faulty section of a circuit and restore supply to the healthy parts of the circuit therefore eliminating the delays caused by operational staff travelling to and switching sections of circuit.[12]

9.59 NIE commenced a small programme of installation in RP4. The 80,000 customers supplied from the circuits targeted in its RP4 work experienced outages of on average two hours a year. After improvement outages were reduced by 30 minutes a year.[13]

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[12] NIE Statement of Case, p95.
[13] ibid, p95.

9.60 The RP5 programme would apply this technology to approximately 150,000 customers who experience similar levels of poor network performance. NIE expects to be able to reduce outages by 20 minutes a year for these customers.[14]

9.61 NIE said that its analysis showed that the investment of £9.0 million in RP5 would result in an improvement of 4.4 CML by 2016/17, which NIE rounded up to 5.0 as a stretch target for this project. One unit of CML means 842,000 minutes lost a year.

9.62 NIE said that research by the UR showed that time taken to restore supply was the most important network issue. In addition research highlighted the difference in experiences between rural and urban consumers.[15]

9.63 NIE said that the UR should not rely on the conclusion that customers in general were satisfied with service standards when disallowing investment specifically designed to benefit rural customers. This was because rural customers' experience of service levels can be very different to that of the average customer.[16]

9.64 BPI thought that although this project would lower CML, it was unlikely that the difference would be substantial enough to be recognized by customers generally.[17] It said that NIE's performance indices compared favourably with the GB DNOs and that this performance could be further improved through operational processes without further expenditure.

9.65 The target benefit is between 4.4 to 5.0 units of CML a year, once the investment is fully completed. We therefore considered whether the target benefit, of the order of

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[14] ibid, pp95 & 96.
[15] ibid, p96.
[16] ibid, p97.
[17] BPI report, p115—to be published.

3.7 to 4.2 million minutes a year, or 62,000 to 70,000 hours a year, was good value at a total capital cost of £9 million.

9.66 We noted that £9 million amounted to an annual cost to customers of around £0.7 million in today's prices.[18] That is, the investment would increase distribution charges by around 0.4 per cent, costing every domestic customer in Northern Ireland an additional 52p a year including VAT if all tariffs are scaled proportionately (or an additional 87p a year including VAT if the money is recovered only from domestic customers) in order to ensure that every year, for 50,000 customers, an interruption that would have lasted an hour and a half without remote control is reduced to a quarter of an hour. We noted that NIE did not present significant evidence of customers' willingness to pay for this investment.

9.67 We provisionally decided that, on balance, this investment was not so compelling that we should allow it as in the public interest.

Non-recoverable alterations

9.68 These costs are incurred when NIE makes an alteration to its network due to a proposed customer development where the cost is not recoverable from the customer. This happens when a development is on land where a Wayleave Agreement is in place.

9.69 We did not identify any good reason why these costs should be treated on a cost pass-through basis (see Section 5). We therefore provisionally decided that these costs are treated the same as NIE's core network investment expenditure with an upfront regulatory forecast and subject to the general cost risk-sharing mechanism.

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[18] Assuming 2.5 per cent depreciation and 4.1 per cent cost of capital, rolled forward to 2013/14 prices using RPI.

We therefore need to make an allowance for non-recoverable alterations within our core network investment allowance.

9.70 NIE forecast £19.7 million in non-recoverable alterations during RP5 (£19.8 million including RASW). This was based on the 2010/11 out-turn with an annual 1 per cent uplift in volumes throughout RP5.

9.71 The out-turn expenditure and number of non-recoverable alterations projects completed in each year of RP4 is shown below in Table 9.6.

TABLE 9.6 **Non-recoverable alterations during RP4, 2009/10 prices**

	2007/08	*2008/09*	*2009/10*	*2010/11*	*2011/12*
Non-recoverable alterations	3.4	4.0	3.6	3.9	3.6
Number of completed projects	964	1,012	873	919	1,040

Source: NIE.

9.72 Table 9.6 shows that the average annual expenditure on non-recoverable alterations during RP4 was £3.7 million. NIE told us that the out-turn in 2012/13 was £3.0 million and that 766 projects had been completed.

Our RP5 forecast

9.73 We decided that a forecast of £3.3 million a year during RP5 was appropriate. This represented the midpoint between the average expenditure for RP4 (£3.7 million) and the out-turn expenditure for 2012/13 (£3.0 million). Over five years this results in a forecast of £16.5 million, which compares with NIE’s forecast of £19.7 million.

Additional CC adjustments to BPI recommendation

9.74 We made adjustments in respect of:

(a) Project D44—Road and Street Works (RASW) legislation;

(b) Project T26—Ballyumford 110 kV switchboard replacement; and

(c) additional allowance for distribution-load-related expenditure.

Project D44—'RASW legislation'

9.75 This project relates to additional cost of RASW legislation in Northern Ireland in RP5. We noted that RASW legislation has not yet been implemented in Northern Ireland, although NIE said that it was expected to be implemented within RP5.

9.76 The UR told us that it had recently spoken to the Street Works Manager in the Roads Service who had informed it that the outstanding elements of the RASW legislation, particularly with respect to fixed penalties and to the fees for the permit scheme, had been reviewed by DETI this year. It said that the manager had confirmed to the UR that there were no plans to enforce these requirements from the legislation in the foreseeable future.

9.77 We asked DETI whether RASW legislation was likely to be implemented during RP5. It told us that it was no longer actively progressing the RASW proposals, although the primary legislation remained in place and it reserved the right to review the position in the future. It said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present.

9.78 Following this response from DETI, NIE said that given the uncertainties regarding implementation of the legislation, it would be content with no upfront allowances on the basis that it would be able to apply the change in law provision if the scheme was implemented.

9.79 We therefore decided that no allowance for RASW legislation should be made in our core network investment forecast. This results in a reduction of £4.4 million to BPI's recommendation.

Project T26—Ballyumford 110 kV switchboard replacement

9.80 NIE requested £15.3 million in respect of this project (including £0.6 million of project management costs). BPI recommended that this project should be included in the RP5 investment programme and made a project allowance of £14.7 million. It excluded £0.6 million of project management costs, which it considered had been allocated in NIE's project design and management consultancy overhead costs.

9.81 NIE confirmed that the project management costs involved in this project were separate from the project design and management consultancy overhead costs which BPI had allocated to it. We therefore allocated a project allowance of £15.3 million (rather than the £14.7 million recommended by BPI). This results in an increase of £0.6 million to BPI's recommendation, to £15.3 million.

Allowance for distribution-load-related expenditure

9.82 As discussed in Section 5, we considered the use of some form of provision or mechanism in the price control to adjust NIE's expenditure allowance according to further specific projects that become necessary. We did not consider that this would be proportionate. Instead, we propose an additional allowance, further to the figure recommended by BPI, for other distribution-load-related investment which may be required in the period.

9.83 NIE submitted a forecast for distribution-load-related expenditure of £24.6 million and BPI recommended an allowance of £22.3 million.[19] BPI recommended a reduction of £1.2 million in respect of 33/11 kV transformers (D36), where it recommended load-related works at nine sites compared with the 15 sites which had been requested by

[19] BPI final report, p33—to be published.

NIE. It also recommended not allowing the Dungannon Main 33 kV switchboard (D27), for which NIE had requested £1.1 million.[20]

9.84 In total, BPI therefore recommended a reduction of £2.3 million compared with NIE's forecast for distribution-load-related expenditure. The reduction was entirely in respect of 33 kV distribution-load-related expenditure. The reduction represents costs forecast by NIE for which there is uncertainty as to the need and timing for investment to increase 33 kV distribution network capacity (eg it will depend on localized load growth).

9.85 Our proposed additional allowance is 50 per cent of £2.3 million (ie £1.15 million), which reflects a view that not all of the potential projects identified by NIE will be needed before 30 September 2017.

Adjusted BPI recommendation

9.86 We revised BPI's core network investment recommendation to reflect our project adjustments described above and also our non-recoverable alterations allowance for RP5. Table 9.7 shows the effect of these adjustments on BPI's recommended capex allowance.

TABLE 9.7 **CC adjustments to BPI's recommended RP5 allowance**

	£m
BPI recommendation	392.6
Additional ESQCR allowance	8.0
Add non-recoverable alterations allowance	+16.5
Remove RASW legislation (D44)	–4.4
Adjust BPI Project management costs (T26)	+0.6
Additional distribution load related allowance	+1.2
Adjusted total	**414.3**

Source: CC analysis (may not sum due to rounding).

[20] BPI final report, p33—to be published.

CC direct costs estimate

9.87 As explained in paragraphs 9.26 and 9.27, we decided that it was very important to estimate the direct cost element of BPI's recommended core network investment allowance (of £414.3 million, as revised in Table 9.7 above).

9.88 Based on NIE's original submission it was not possible for us fully to separate out all indirect costs to derive a direct-only allowance. This was because of the way in which NIE reports data.

9.89 The indirect costs on which we have benchmarked NIE are contained in the following areas of NIE's core network investment forecast:

(a) Five separately identified overhead projects in NIE's capex submission. These are Capitalized Overheads (D45 and T41), Distribution Overhead Fixed Lines (D12) and Design & Consultancy (D20 and T23). These projects are wholly indirect costs.

(b) The Fault & Emergency (D17; T21) and Reactive (D18; T22) projects. Our benchmarking covers these costs in their entirety.

(c) Tree Cutting (TAR), which is one element of the cost of the OHL asset replacement programmes within Transmission (T17; T19) and Distribution (D7; D8; D9). Our benchmarking includes TAR.

(d) Within the charge-out rate for Powerteam. This charge-out rate is contained is used to build up the individual project costs and as a result individual capex projects will contain an element of indirect costs which cannot be easily separated.

9.90 In order to identify the direct cost element of BPI's recommendation we needed to subtract the indirect costs from *(a)* to *(d)* above. In the following section we explain our approach to doing this.

Our approach to estimating direct costs

9.91 BPI's recommendation in respect of the five separately identified wholly indirect projects is shown below in Table 9.8.

TABLE 9.8 **BPI's recommendation for indirect overheads projects**

	£m
Capitalised overheads—Distribution (D45)	18.2
Capitalised overheads—Transmission (T41)	2.3
Design & Consultancy—Distribution (D20)	3.4
Design & Consultancy—Transmission (T23)	6.2
Overhead Lines Fixed Costs—Distribution (D12)	0.0
Total	**30.1**

Source: BPI final report.

9.92 It can be seen from Table 9.8 above that BPI included an allowance of £30.1 million in respect of indirect-only projects (£27.2 million less than NIE's submission). To reach a direct-only allowance we therefore excluded BPI's allowances for each of these projects (a total of £30.1 million).

9.93 BPI allocated the amounts shown below in Table 9.9 to Fault & Emergency and Reactive projects.

TABLE 9.9 **BPI's recommendation for Fault & Emergency and Reactive projects**

	£m
Fault & Emergency (D17)	12.9
Fault & Emergency (T21)	2.9
Reactive (D18)	8.7
Reactive (T22)	0.5
Total	**25.1**

Source: BPI final report (may not sum due to rounding).

9.94 These activities are fully included within our benchmarking and we therefore excluded these projects in our estimate of direct-only costs.

9.95 NIE's submission included £33.25 million in respect of tree cutting costs. BPI excluded £3.4 million of tree-cutting costs,[21] leaving £29.8 million of tree-cutting costs still in BPI's recommendation. Tree cutting is included within our benchmarking and we therefore excluded these costs from our estimate of direct-only costs.

9.96 In order to estimate the level of indirect costs included in NIE's individual projects we made use of the direct unit cost benchmarking report prepared for NIE by PB Power (PB). In this report PB benchmarked a sample of the direct unit costs contained in NIE's capex forecast against the GB DNOs.

9.97 Since the GB DNO unit cost data was prepared on a direct cost basis it was necessary for PB to adjust NIE's unit costs (which contain an element of indirect costs) to make them comparable. PB therefore adjusted NIE's unit costs to estimate its direct cost only; it concluded from its analysis that NIE's direct unit costs were efficient.

9.98 We have mapped the direct unit costs used PB's in benchmarking exercise to NIE's capex submission. This gives us a sample from which it is possible to make a number of observations regarding the level of indirect costs included in NIE's projects.[22]

9.99 Our sample of projects totalled £282.5 million, around 72 per cent of NIE's core asset replacement and load-related submission of £393.5 million.[23] Within these projects we were able to identify unit costs with a total value of £193.5 million (49 per cent of NIE's asset replacement and load-related submission) which PB Power had used in its analysis. Our analysis of this sample showed:

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[21] From projects D7; D8; D9.
[22] Direct unit cost sample and method provided to the parties on 23/9/2013.
[23] Excludes the following projects: Overheads, Storms, ESQCR, IT, Fault & Emergency/Reactive, Smart Grid, Customer Priorities.

(a) £35.8 million of indirect costs and £157.7 million of indirect costs, implying that total costs were 22.7 per cent higher than direct-only costs;

(b) there was a marked difference between the percentage of indirect costs in overhead line (OHL) projects and other asset replacement and load-related projects (such as plant or cable replacement projects). In the sample total OHL project costs were 44.5 per cent higher than direct-only costs; for other asset replacement and load-related projects total costs were only 5.1 per cent higher; and

(c) our sample was quite heavily weighted towards OHL projects, which represented 53 per cent of our sample (based on total project costs).

9.100 We noted that analysis presented by Frontier as part of its benchmarking of NIE's indirect costs and R&M costs against GB DNOs showed that a figure of 72.0 per cent[24] was appropriate for this category (although we have excluded Fault & Emergency and Reactive categories which this analysis would be relevant to).

9.101 We judged that it was possible to use the results of our sample analysis to estimate the amount of direct costs and indirect costs which were contained within projects which BPI had approved. We did this in the following way:

(a) We split BPI's approved projects into two main categories: OHL projects; and other asset replacement and load related projects:

(i) for OHL projects we estimated that direct costs were 69.2[25] per cent of total project costs; and

(ii) for other asset replacement and reinforcement costs we estimated that direct costs were 95.2 per cent[26] of total project costs.

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[24] As part of our benchmarking analysis of indirect costs and inspections, maintenance, faults and tree-cutting costs (IMF&T) we have drawn on data and analysis provided in Excel models prepared for Frontier Economics for NIE, in particular, the model accompanying NIE submissions of 2 August 2013. Aside from an adjustment to the calculation of IMF&T costs to include an estimate of NIE's pension costs, we used the estimates of IMF&T costs from the Frontier model and produced a decomposition of these costs between direct and indirect costs. This exercise produced an estimate that 72 per cent of capitalized IMF&T costs in 2009/10 were direct costs. We have used the figure of 72 per cent to estimate the direct cost element of non-recoverable alterations.

[25] Assumes direct-only project costs are uplifted by 44.5 per cent to reach Total project costs. 100/144.5 = 69.2 per cent.

(b) We assumed that ESQCR costs were an entirely separate allowance and we have therefore allocated these costs in full (that is an allocation of 100 per cent).

(c) For non-recoverable alterations we assumed a similar ratio of direct to indirect costs as shown in Frontier's benchmarking (see paragraph 9.98). That is, direct costs are 72.0 per cent of total costs.

(d) For the IT costs and our additional distribution-load-related expenditure allowance we assumed a similar rate to our other asset replacement and reinforcement costs. That is, direct costs are 95.2 per cent of total costs.

9.102 Applying the relevant adjustment factors above to each of the projects approved by BPI resulted in a direct-only core network investment estimate of £282.6 million. Table 9.10 shows the results of this analysis.

TABLE 9.10 **CC estimate of direct-only core network investment**

	BPI recommended project value (CC adjusted) £m	*Adjustment factor applied %*	*Estimate for direct-only costs £m*
Transmission			
OHL	18.4	69.2	12.7
Other asset management and replacement	86.4	95.2	82.2
Distribution			
OHL	83.2	69.2	57.6
Other asset management and replacement	104.3	95.2	99.2
Other			
Smart Grid	3.0	95.2	2.9
Customer priorities	2.3	95.2	2.2
ESQCR	10.3	100	10.3
Non-recoverable alterations	16.5	72.0	11.9
CC additional distribution load related allowance	1.2	95.2	1.1
IT	3.7	95.2	3.5
Total	**329.3**		**283.7**

Source: CC analysis (figures may not sum due to rounding).

9.103 Our estimate of the direct-only elements of BPI's recommendation is therefore £283.7 million, which compares with a recommendation of £414.3 million including indirect costs (see paragraph 9.84 and Table 9.7). A reconciliation between the

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[26] Assumes direct-only project costs are uplifted by 5.086 per cent to reach Total project costs. 100/105.086 = 95.2 per cent.

original BPI allowance and our CC estimate of direct-only costs is shown in Table 9.11.

TABLE 9.11 **CC reconciliation of BPI core network investment recommendation to CC direct cost only estimate**

	£m
BPI recommendation per report	392.6
Additional ESQCR allowance	8.0
Add non-recoverable alterations allowance	+16.5
Remove RASW legislation (D44)	–4.4
Adjust BPI Project management costs (T26)	+0.6
CC additional distribution load related allowance	+1.2
Adjusted total	**414.3**
Indirect costs deducted:	
Indirect cost projects	–30.1
Tree cutting	–29.8
Fault & Emergency and Reactive	–25.1
Estimate of indirect costs embedded in projects	–45.6
Direct-cost-only estimate	**283.7**

Source: CC analysis.

Adjustments required for time periods

9.104 NIE prepared its RP5 submission on the basis of a five-year period. Our cost assessment period runs from April 2012 until September 2017 and is a 5.5-year period. We therefore considered what adjustments to our core network investment allowance might be necessary given that our cost assessment period was six months longer than the period which NIE had originally assumed in its submission.

9.105 We asked NIE what core network investment it had completed in 2012/13 and what it forecast for 2013/14 based on current run rates. NIE's response is shown below in Table 9.12.

TABLE 9.12 **NIE's actual/forecast core network investment in 2012/13 and 2013/14**

		£ million
	2012/13 actual	*2013/14 forecast*
Core network investment	52.7	62.1

Source: NIE.

Note: Does not include non-recoverable alterations.

9.106 We noted that NIE's forecast for 2013/14 already contained a significant increase in core network investment in the first quarter of 2014. For January to March 2014 NIE forecast £20.1 million of core network investment, as compared with £12.4 million in the comparable quarter in 2013 (an increase of 62 per cent).

9.107 We also noted that BPI had concluded that the proposed investment programme involved a considerable amount of network development.[27]

9.108 We considered what the implied increase in the annual investment rate would be, assuming a five-year cost assessment period. That is, assuming that NIE completed the remaining core network investment over a three-year period.[28] The result is shown in Table 9.13.

TABLE 9.13 **Implied increase in annual investment rate for core network investment assuming a five-year cost assessment period**

	£m
CC direct-only allowance for RP5 (excluding non-recoverable alterations)*	271.8
CC benchmarked capitalized indirect costs (assume 5-year allowance)	127.1
CC total capex allowance (excluding non-recoverable alterations)*	398.9
Less: core network investment undertaken in 2012/13 and forecast for 2013/14	–114.8
To complete	284.1
Per year (assuming 3.0 years remaining)	94.7
Uplift on 2012/13 actual (%)	79.7

Source: CC analysis.

*Excluding non-recoverable alterations to make comparison on a like-for-like basis.

9.109 Table 9.13 above shows that, assuming a five-year cost assessment period, a 79.7 per cent increase in annual run rate for core network investment would be required. If we instead assume a 5.5-year cost assessment period (in line with our

[27] BPI final report, p30—to be published.
[28] Here we assume two completed years (April 2012–March 2014) leaving three years remaining of a five-year cost assessment period.

provisional decision), the increase in annual run rate falls to 54 per cent.[29] In our view, this still represents a challenging increase in run rate for the remainder of RP5.

9.110 We considered whether the implied increase in core network investment for the remainder of the cost assessment period was so great that our allowance should be reduced. We provisionally decided against this approach because, whilst the run rate is challenging, all the projects included in our allowance had been assessed as being well justified in RP5.

9.111 We then considered which of the projects recommended by BPI it would be necessary to adjust (ie increase by 10 per cent)[30] in order to make the allowance appropriate for our longer cost assessment period. We decided that it was not appropriate to scale up the vast majority of core network investment projects. This is because we considered that the investment ramp-up was already very challenging and that the vast majority of projects could simply be delivered to a slightly later date.

9.112 However, we provisionally concluded that it would be appropriate scale up certain projects to reflect a longer cost assessment period. These were:

(a) Capitalized Overheads (D45 and T41);

(b) Distribution Overhead Fixed Lines (D12);

(c) Design & Consultancy (D20 and T23);

(d) Fault & Emergency (D17 and T21);

(e) Reactive (D18 and T22) projects; and

(f) non-recoverable alterations.

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[29] Total capex £438.8 million (5.5 years of indirect costs) minus £114.8 million completed leaves £324 million over 3.5 years (£92.6 million).

[30] To adjust for a 5.5-year revenue control rather than a 5.0-year revenue control, ie 5.5/5.0 = 1.1.

9.113 Items *(a)* to *(e)* are included in our indirect cost benchmarking exercise. Our indirect cost allowance will be time dependent and therefore reflect a longer cost assessment period. Non-recoverable alterations are not included in our indirect cost benchmarking exercise. It is reasonable to assume that this work will be approximately 10 per cent higher over a 10 per cent longer period; indeed we have prepared our RP5 forecast on the basis of an annual allowance (see paragraph 9.75).

9.114 We therefore scaled up our non-recoverable alterations project allowance to reflect a 5.5-year cost assessment period. This increases our direct-only core network allowance by £1.2 million to £284.9 million.

Provisional determination

9.115 We have approached NIE's core network investment allowance in the following way:

(a) We have used BPI's report as a starting point. BPI's recommendation was based on those projects which it judged had been sufficiently well justified in NIE's core network investment plan.

(b) We have used BPI's recommendations with regard to the volumes of work that should be completed in RP5.

(c) We have applied additional scrutiny to three of NIE's projects, which stood out to us as requiring an additional review (see paragraphs 9.29 to 9.69). On this basis we added an additional £8 million to NIE's allowance for complying with ESQCR legislation (Projects D43 and T40).

(d) We have made additional adjustments in respect of non-recoverable alterations (see paragraphs 9.68 to 9.72),RASW legislation (see paragraphs 9.75 to 9.79), project management costs for the Ballyumford switchboard project (see paragraphs 9.82 and 9.83) and an additional allowance for distribution-load-related expenditure (see paragraphs 9.82 to 9.85).

(e) After making the adjustments in *(c)* and *(d)* our adjusted core network investment allowance was £414.3 million (see paragraph 9.84).

(f) We then adjusted this allowance to reflect only direct costs. Our direct-only core network investment allowance was £283.7 million (see paragraphs 9.87 to 9.103).

(g) Finally, adjusting our direct-only allowance for a longer cost assessment period increased our allowance to £284.9 million for RP5 (see paragraphs 9.102 to 9.112).

33 kV network limitations for small-scale renewable generation

9.116 We note that, just prior to our provisional determination, NIE submitted that an ex-ante allowance for network reinforcement relating to small-scale renewable generation should be included in our cost allowances. This expenditure covers network reinforcement which is caused by the increase in small-scale renewable generation. The connection charges which small-scale generators pay to connect to the electricity network do not currently cover this reinforcement work.

9.117 NIE estimated that, for the period between October 2014 and September 2017, this reinforcement work could require an ex-ante allowance of around £30 million, although this amount was at present uncertain.

9.118 Given the limited time which we have had to consider this point, we do not at this stage make a provisional determination on this issue. In light of our provisional determination, we invite further submissions from the parties as to how this issue is best dealt with within the price control design structure we have provisionally proposed (see Section 5).

10. Other elements of cost assessment

10.1 This section addresses other elements of our cost assessment that are not covered in either our assessment in Section 8 (NIE's indirect costs and its costs of IMF&T) or Section 9 (NIE's direct costs or its network investment).

10.2 Our approach to cost assessment differs from that taken by the UR. This is particularly so in relation to our assessment of IMF&T costs. We have placed greater weight than the UR on estimated cost benchmarks from comparisons of the costs of the GB DNOs and less weight than the UR on NIE's historical costs or NIE's fore-casts. As a result, some of the specific criticisms that NIE makes in its Statement of Case about the UR's cost assessment are not directly relevant to our approach. Nonetheless, we have taken account of NIE's submissions, and the analysis underpinning the UR's RP5 Final Determination, as part of the application of our approach.

10.3 In addition to the cost allowances for NIE that we have provisionally determined in Sections 8 and 9, we have identified three grounds for additional cost allowances or adjustments:

(a) Some categories of costs (eg rates and licences fees) are not included in the cost benchmarks used in Section 8. Nor are they covered in our assessment of NIE's network investment direct costs. We need to make separate allowances for them.

(b) We make adjustments for differences in the services or outputs provided by NIE compared with the GB DNOs that we have used for our benchmarking analysis. For example, NIE installs and replaces electricity meters and carries out meter reading and we make separate assessments of the costs of these services.

(c) We consider potential adjustments for the impact on costs of anticipated changes in the services, outputs or obligations that NIE faces—to the extent that these are not already captured in the cost allowances set using GB DNO cost benchmarks.

10.4 Table 10.1 sets out the different elements of costs covered in this section and provides the rationale for their inclusion by reference to these points.

TABLE 10.1 **Cost allowances and adjustments**

Cost item and cross-reference	*Rationale for separate cost assessment or adjustment*
Rates under the Valuation (Electricity) Order (Northern Ireland) 2003 (paragraphs 10.8 to 10.21)	Not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs
	Business rates incurred by GN DNOs are reported as part of 'non-activity-based costs' and are not included in either direct or indirect costs
Licence fees (paragraphs 10.22 to 10.27)	Not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs
	Licence fees incurred by GB DNOs are reported as part of 'non-activity-based costs' and are not included in either direct or indirect costs
Non-network capex (paragraphs 10.28 to 10.60)	Non-network capex not covered in our benchmarking analysis of indirect and IMF&T costs or in our assessment of NIE's network investment direct costs
	Costs of non-operational capex for GB DNOs reported separately from direct and indirect costs
Metering capex (paragraphs 10.61 to 10.95)	Services provided by NIE that are not provided by GB DNOs
Metering reading (paragraphs 10.96 to 10.106)	Services provided by NIE that are not provided by GB DNOs
Other operating costs related to Keypad meters (paragraphs 10.107 to 10.109)	Services provided by NIE that are not provided by GB DNOs
Overheads for metering and market opening (paragraphs 10.110 to 10.112)	Administrative costs and overheads for services provided by NIE that are not provided by GB DNOs
Enduring Solution (paragraphs 10.113-10.179)	Services provided by NIE that are not provided by GB DNOs
Connection charges funded through RAB (paragraphs 10.180 to 10.192)	Time-limited 'subsidy' to certain connection charges from use of system charges
	Costs of subsidy not covered in cost base for GB DNO benchmarking analysis
Storm costs in atypical severe weather (paragraphs 10.193 to 10.203)	Not covered in our benchmarking analysis of indirect and IMF&T costs
	The Ofgem data report we have used reports costs relating to atypical severe weather events separately and we have not included these in our benchmarking
Costs associated with aggregated generator units (paragraphs 10.204 and 10.205)	Services provided by NIE that are not provided by GB DNOs

Source: CC.

10.5 In addition we considered whether our cost allowance for NIE should be offset by an estimate of revenues that NIE expects to receive from other sources of which we have not already taken account. We consider the element of connection charges associated with operation and maintenance (O&M) (paragraphs 10.206 to 10.209) and revenue protection income (paragraphs 10.210 to 10.212).

10.6 We also discuss a number of other issues raised by the parties that we have taken account of as part of our provisional determination of a cost allowance for NIE (paragraphs 10.213 to 10.255).

10.7 Finally, our cost assessment does not seek to make adjustments for the anticipated transfer of transmission planning activities to SONI. We discuss the implications of the SONI transfer for our determination at the end of this section (paragraphs 10.256 to 10.261).

Rates under the Valuation (Electricity) Order (Northern Ireland) 2003

10.8 NIE pays rates in respect of its network, under the Valuation (Electricity) Order (Northern Ireland) 2003. These are determined by reference to formulae based on transmission circuit length and MVA transformer capacity.

10.9 In its Statement of Case, NIE forecast rates liabilities of £69 million over the RP5 period (2009/10 prices). Tables 10.2 and 10.3 below provide a decomposition of the rates forecast provided in NIE's original Statement of Case. NIE provided forecasts in 2009/10 prices and nominal prices. The figures are for financial years running from 1 April to 31 March.

TABLE 10.2 **NIE forecast of rates**

£ million, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Core	12.6	12.7	12.7	12.8	12.9
Renewables and North–South Interconnector	0.5	0.7	1.0	1.4	1.6
Total	13.1	13.4	13.8	14.2	14.5

Source: NIE.

TABLE 10.3 **NIE forecast of rates**

£ million, nominal prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*
Core	14.2	14.8	15.3	15.8	16.4
Renewables and North–South Interconnector	0.6	0.8	1.2	1.8	2.1
Total	14.8	15.6	16.5	17.6	18.5

Source: NIE.

10.10 NIE's forecasts above distinguish between the rates liability for its 'core' network and the liability associated with network expansion including investment in the planned North–South interconnector and investment to accommodate renewable generation.

10.11 During the inquiry we asked NIE for updated forecasts. NIE said that its forecast in respect of the core network (ie excluding renewables and North–South inter-connector) remained as used in its Statement of Case and reproduced above under 'core'.

10.12 NIE said that its forecast rates liability associated with renewables and the North–South interconnector would depend on the roll-out of these programmes, which had been delayed. NIE subsequently provided an updated forecast of its additional rates liability associated with renewables and the North–South interconnector. NIE said that its updated forecasts 'have reduced significantly due to delays in the roll-out of renewables projects plus the delay in the North/South Interconnector project'. NIE's updated forecasts were for no additional rates liability under the heading 'Renewables and N/S Interconnector' in the years 2012/13, 2013/14 and 2015/16 and a liability of around £0.1 million in 2015/16 and 2016/17.

10.13 NIE cautioned that its forecasts beyond 2015 were speculative at this stage since a rating revaluation was expected to take place in 2015 and this would change the key variables on which the rates were based.

10.14 NIE also provided information on actual and provisional rates liabilities in 2012/13 and 2013/14:

(a) NIE's actual rates liability for 2012/13 was £14.2 million (nominal prices). This is in line with NIE's (nominal) forecast for 2012/13 for 'core' rates above.

(b) NIE received a rates bill of £14.6 million for 2013/14 (nominal prices). NIE said that this bill was an estimate and potentially subject to revision. This figure is about £0.2 million less than NIE's nominal forecast for 'core' rates above.

10.15 This information shows that for 2012/13 and 2013/2014, an allowance for rates based on NIE's forecast liability for what it calls 'core' network would have been sufficient to cover its total liability (£0.2 million more than sufficient if the rates bill for 2013/14 is not revised).

10.16 We propose a cost allowance for NIE's rates liability based on its forecast for core rates above.

10.17 We also need a forecast that runs to 30 September 2017, whereas NIE's forecasts run to 31 March 2017. For the six-month period from 1 April 2017 to 30 September 2017, we have calculated an allowance by extrapolating NIE's core forecast to produce a figure of £13.0 million for the financial year from 1 April 2017 and dividing this by two.

10.18 Our allowances for rates will be subject to RPI indexation. We do not propose any RPE or ongoing productivity adjustments as part of the calculation of these allowances for rates.

10.19 We do not consider it necessary to make any additional allowance in relation to NIE's updated forecasts for rates associated with 'renewables' and the North–South interconnector. There appears to be considerable uncertainty about the investment projects that NIE expects to lead to an increase in its rates. Further, under our proposals (see paragraphs 5.250 to 5.269), the development of transmission and interconnection projects would be dependent on a project-level approval by the UR. We propose that, if the UR approves any additional NIE investment projects to increase the capacity of the transmission system, the UR should consider whether delivery of these projects gives rise to any significant incremental rates liability in the period to 30 September 2017 and, if so, include an allowance in the cost assessment for that project approval. Neither the UR nor NIE should seek to use that opportunity to make any adjustments to NIE's price control for changes to NIE's rates liability.

10.20 We recognize that the anticipated rating revaluation could affect NIE's rates. We do not know whether this revaluation will increase or decrease rates. We have not sought to take account of the impact of the anticipated revaluation on our forecasts.

10.21 We have not used the forecasts of NIE's rates contained in the UR's Final Determination. The UR said that it considered its forecast annual amount of £13.1 million (2009/10 prices) for the RP5 period to be generous to NIE. The UR's figure from its Final Determination is higher than NIE's recent forecasts. The UR did not seek to revise its rates forecasts ahead of our provisional determinations.

Licence fees

10.22 We have proposed that the licence fees set by the UR that NIE is required to pay are subject to a pass-through mechanism intended to remove NIE's financial exposure to these costs and to pass them on to consumers.

10.23 We propose a mechanism in which we include in the calculation of the price control a forecast of NIE's licence fees for each year of the price control and combine this with an adjustment mechanism for any differences between forecast and out-turn licence fees.

10.24 In its calculations for its Final Determination, the UR had used a figure of £0.8 million for licence fees for the first year of its RP5 Final Determination, and figures for subsequent years that declined by 5 per cent per year.

10.25 NIE told us that its actual licence fees incurred in 2012/13 and 2013/14 were £1.0 million and £2.2 million respectively in nominal prices or £0.9 million and £1.9 million in 2009/10 prices.

10.26 We have not considered the potential trajectory of licence fees in any detail, especially given the impact of the pass-through mechanism which limits the importance of these forecasts.

10.27 We used in our calculations a forecast of £1.9 million per year, which reflects the most recent information available to us.

Non-network capex: ICT

Background

10.28 NIE incurs ICT costs in running its network. Historically these costs have been treated as an opex allowance for tariff purposes because the replacement cycles for these items are substantially shorter than for most network-related capex.[1]

10.29 NIE forecast a requirement for £15.1 million for non-network capex in RP5. This represented an increase of 49 per cent on the RP4 out-turn of £10.2 million. A summary breakdown of this forecast is shown below in Table 10.4.

[1] NIE Statement of Case, pp177&178.

TABLE 10.4 **NIE's non-network capex forecast**

	£ million	
	RP4	*RP5*
IT Infrastructure	4.5	5.9
Corporate telecoms	1.6	1.4
Business IT	4.0	7.7
Total	10.2	15.1

Source: NIE.

Note: The total includes an additional £0.1 million for Renewables Development Group which has not been included as a separate category.

10.30 The UR allowed NIE £7.6 million for non-network capex in its RP5 Final Determination.

Views of the parties

10.31 NIE said that non-network ICT capex consisted of three main components. It said that its cost forecast was built from the bottom up:

(a) *IT infrastructure (£5.9 million)*. This investment is required to upgrade and develop the data centre and desktop hardware used to operate and access NIE's business applications. The need for refresh is driven by five-year replacement cycles for all equipment with the exception of laptops, where the cycle is three years.

(b) *Telecoms infrastructure (£1.4 million)*. This investment is required to upgrade and develop NIE's business voice and data telecoms network. The need for refresh is driven by five-year replacement cycles for business voice and data telecoms equipment.

(c) *Business applications (£7.7 million)*. This investment is required to introduce the IT applications needed to meet new business requirements and upgrade existing applications to maintain supportability.[2]

[2] ibid, p179.

10.32 NIE said that the 49 per cent (£5.0 million) increase in forecast expenditure for RP5 compared with RP4 was driven by two main factors. These were:

(a) Several large hardware components will reach end of life during RP5; minimal expenditure had been required in these areas during RP4. This has resulted in an increase of £1.4 million in IT Infrastructure investment for RP5.

(b) There is anticipated spend of £2.8 million on SAP during RP5. This is driven by the need to consolidate NIE financial and materials management functionality (currently provided from the Viridian Group SAP platform) on to the NIE SAP platform being implemented for Enduring Solution, followed by the requirement to upgrade the entire platform at the end of the period.

10.33 NIE said that if we established a mechanism whereby additional items of expenditure could be separately approved by the UR then NIE was content that £1.4 million of the SAP spend (for a SAP IS-U upgrade) is removed from the non-network capex submission. A separate approval request for this upgrade project could then be submitted by NIE during the course of RP5.

10.34 NIE submitted that the non-network capex proposed in the Final Determination was inadequate and did not allow it to ensure that important ICT applications and infrastructure remained fit for purpose through RP5.[3]

10.35 It said that the UR had ignored the recommendations made by Gemserv (the UR's consultants) when making its allowance for RP5. With regard to the Gemserv report NIE said that: it was it was unclear on what basis Gemserv had developed its allowance; and it was unclear why Gemserv's more superficial approach was more appropriate than NIE's detailed bottom-up review.

[3] ibid, p182.

10.36 NIE said that Powerteam did not incur any ICT capex costs and that therefore no such costs were included in its charges. All non-network ICT capex was incurred by NIE. It said that the reasoning behind the UR's 50 per cent disallowance was therefore wrong.[4] NIE said that its non-network capex submission included costs for the implementation, replacement and upgrade of NIE's IT and Telecoms assets. All of these assets were owned by NIE and none of the depreciation associated with these assets was charged to NIE Powerteam.

10.37 It submitted that there was no double counting of costs;[5] nor was there reason to be concerned with the NIE/Powerteam arrangement as regards cross-subsidy. This is because Powerteam provides services exclusively to NIE and recovers its costs from NIE.

10.38 The UR commissioned Gemserv to review NIE's non-network capex proposal. Gemserv conducted a top-down analysis of NIE's requirements for RP5 because it could not reconcile the NIE bottom-up cost table with the supporting evidence. It concluded that:

(a) there was insufficient information to provide an independent view of the NIE request, especially because NIE had varying degrees of confidence in its own cost projections;

(b) it agreed with the principle of IT System rationalization, but the benefits of migrating legacy systems to SAP had not yet been proved; and

(c) there was no proven business case to support some of the non-critical business items included in the planned investment portfolio.

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[4] ibid, p178.
[5] The UR said that this statement contradicted the information provided to the UR in the BPQ on 11 February 2011 and subsequently submitted to the CC with NIE's Statement of Case.

10.39 Gemserv said that it had therefore concluded that using RP4 as the basis for the allowance during RP5 was the most appropriate way forward. It said that using this approach it believed that an allowance of £12.3 million for RP5 should be adequate for NIE's requirements and allow it to comply with its licence obligations during RP5. Table 10.5 below summarizes Gemserv's conclusions.

TABLE 10.5 **Gemserv's conclusion on non-network capex for RP5**

£'000

	Predicted RP4 out-turn	*Gemserv recommended changes for RP5*	*Proposed allowance for RP5*
IT infrastructure	4,540	250	4,790
Corporate telecoms	1,634	–235	1,399
Business IT	4,042	725	4,767
Renewables development group	6	74	80
SAP finance		750	750
Business innovation		500	500
Total	10,222	2,064	12,286

Source: Gemserv.

10.40 It can be seen from Table 10.5 that Gemserv made a number of adjustments to the RP4 out-turn to reach its allowance of £12.3 million. These were:

(a) *IT infrastructure.* An additional allowance of £250,000 was included to cover items such as additional security and other Internet infrastructure requirements.

(b) *Corporate telecoms.* Gemserv found no reason to disagree with NIE's proposed budget for RP5, which was for a reduction of £235,000 compared with RP4.

(c) *Business IT applications.* An additional £250,000 was allowed for the UR's requirement for a new reporting system. Gemserv allowed an additional £475,000 for the cost of a street works system,[6] which was 50 per cent of NIE's request. This disallowance was because Gemserv considered that NIE's submission represented the total, rather than incremental, cost of the project. It considered that this allowance might be generous.

[6] Mainly related to record management.

(d) *Renewable Development Group.* This is considered required new expenditure for RP5.

(e) *SAP Finance.* NIE currently uses the Veridian Group (VG) finance system. This project represents the cost of migrating all finance and materials functionality to a new NIE SAP system (Enduring Solution) from the VG system. Gemserv recommended a 50 per cent reduction in NIE's request in this area. This was because: an element of the cost was necessitated by the sale of NIE to ESB; competitive tendering may reduce the costs further; and the Enduring Solution project is investing heavily in the provision of financial data.

(f) *Business innovation.* This is an allowance to encourage NIE to look for IT systems to support business innovations that provide customer benefits and drive down costs.

10.41 The UR said that the £12.3 million allowance proposed by Gemserv was not comparable with the £15.2 million NIE forecast. This was because the Gemserv recommendation excluded £1.4 million relating to a partial refresh of Enduring Solution which was deemed not sensible as a stand-alone implementation and which could be delayed until the start of RP6 or incorporated in a future smart metering project. On a like-for-like comparison Gemserv's £12.3 million proposal was therefore only £1.3 million different from NIE's forecast.

10.42 The UR said that it believed that the costs associated with Powerteam should form part of the unit rates or indirect costs which had been benchmarked in other parts of RP5. It said that approximately 50 per cent of the request for non-network capex covered Powerteam staff and this is why it disallowed 50 per cent of the request. It said that NIE had sufficient IT resources to discharge its duties.[7] The costs

[7] UR Final Determination, Appendix D, p81.

associated with IT (both capex and opex) should be included within the Business Support costs which we have benchmarked against the GB DNOs.

10.43 The UR said that Powerteam was supposed to be comparable to an independent contractor and therefore any cross-subsidies to a sister company under the price control and double counting of costs should be avoided. It said that NIE did not provide a breakdown between the equipment required for its own staff and those of its sister company.

10.44 The UR said that it did not have confidence that NIE's requested costs were in addition to costs which it had already approved. It said that it did accept that some costs were required and in the absence of tangible evidence it made the assumption that 50 per cent of the request related to Powerteam and 50 per cent to NIE. It said that if it had apportioned costs on the basis of staff numbers this split would have resulted in an allowance of approximately only 25 per cent.

Pelicam advice

10.45 We commissioned Pelicam, a specialist IT Project Assurance consultant, to provide high level advice on NIE's non-network capex submission. Pelicam had access to all relevant non-network capex documentation. In addition it attended a formal meeting between us, NIE, the UR and Gemserv.

10.46 Pelicam said that NIE was planning to spend £5.9 million on new IT infrastructure during RP5 with no apparent benefit to the customer other than 'keeping the lights on'. It said that it was hard to imagine an unregulated company allowing such a large-scale IT investment with zero return on investment.

10.47 Pelicam took the view that NIE could not demonstrate that it was approaching least cost for its IT opex. It concluded that NIE could reduce its IT opex through a combination of competitive bidding, some degree of offshoring and further IT infrastructure optimization.

10.48 Pelicam recommended that NIE be awarded £30,000 for an IT specialist to manage a comprehensive legacy software evaluation and testing programme rather than £400,000 for modifying legacy software. It was of the view that £400,000 was a risk-averse provision.

Our provisional decision on non-network capex and RP5 forecast

10.49 We considered NIE's BPQ submissions as well as the UR's responses and the Gemserv report which it commissioned. We also asked the parties for clarification and we held a hearing with the parties, our adviser (Pelicam) and the UR's adviser (Gemserv).

10.50 We first considered whether we should apply a discount to NIE's forecast, for the reasons outlined by the UR in paragraphs 10.42 to 10.44. That is because the costs submitted by NIE had already been (or should have been) accounted for elsewhere.

10.51 The evidence submitted by NIE (see paragraphs 10.36 and 10.37 above) stated clearly that there was no double counting of costs between Powerteam and NIE. NIE also said that none of the depreciation associated with the non-network capex assets was charged to Powerteam. We therefore found that it would not be appropriate to disallow any of NIE's submission because of double counting of costs between NIE and Powerteam.

10.52 We then considered whether to use Gemserv's report as a basis for setting the RP5 allowance. This report used a top-down approach based on NIE's RP4 allowance; it concluded that an allowance of £12.3 million was appropriate. Gemserv made allowances for a number of additional projects in the RP5 period (see paragraph 10.40) and also scaled down a number of NIE's projections for RP5.[8]

10.53 Whilst we welcomed the insights which this report provided, we provisionally decided against using the same approach because we were concerned that replacement cycles could mean that an appropriate RP5 allowance might be significantly different from the allowance from RP4. For example, significantly fewer (or many more) items may be due for replacement in RP5 compared with RP4.

10.54 We provisionally decided to use NIE's BPQ submission as a basis for our RP5 allowance. We then made the following adjustments:

(a) First, we excluded £1.4 million for an upgrade to the Enduring Solution SAP IS-U platform. This is because the business case for this part of the upgrade has not yet been finalized. NIE said that it was happy for this to be removed from its submission. In our view if the business case for this upgrade has not been finalized then it should not be included in the RP5 allowance.

(b) Second, we excluded £400,000 relating to modifying legacy software. This is because both Gemserv and Pelicam believed that this was a very risk-averse provision (see paragraph 10.48). Instead, we included a £30,000 allowance for an IT specialist to manage a comprehensive legacy software evaluation and testing programme, as recommended by Pelicam.

[8] The UR said that Gemserv's analyses did not differentiate between costs incurred by Powerteam and those incurred by NIE. Gemserv did not have visibility of the other work that the UR was undertaking in relation to indirect cost benchmarking and the overall costs of services provided by Powerteam. The UR based its decision on the totality of the information available to it, not only this one report.

(c) Third, we excluded £350,000 relating to RASW legislation. NIE said that removing the additional RASW requirements would reduce required investment to £0.75 million (from £1.1 million) during RP5.

10.55 Items (a) to (c) in paragraph 10.54 above amount to total reduction in NIE's allowance for RP5 of £2.12 million. NIE's RP5 submission was for £15.05 million. Our provisional allowance for non-network capex in RP5 is therefore £12.93 million, which represents a 26 per cent increase in expenditure compared with RP4.

10.56 We considered whether we should increase this allowance to reflect a longer RP5 period than was envisaged by NIE when it prepared its submission (our RP5 period ends in September 2017 rather than March 2017). We noted that NIE's actual expenditure on non-network capex in 2012/13 was £1.48 million, compared with an implied run rate of £2.35 million a year in our allowance. Our allowance therefore already assumes a substantial increase in run rate to £2.54 million a year for the remainder of the period. This represents an increase of 72 per cent compared with 2012/13 actual expenditure.

10.57 We also noted that this allowance related to capex items, rather than expenditure on overheads. We did not consider that there was any reason why these capital investments could not be made over a slightly longer period (an additional six months) and we therefore made no adjustment.

Treatment of non-network capex as opex

10.58 Non-network capex is currently treated as an opex item rather than being capitalized into the RAB and expensed over a number of years. This means that this expenditure is paid for immediately by current customers rather than being spread over a number of years. We considered whether it was in the public interest for this treatment to continue.

10.59 The RAB is a means of allowing NIE to recover capital investments over a suitable period determined by the regulator. In our view the most appropriate treatment for capital items such as non-network capex is for them to be capitalized and depreciated over a time period which broadly reflects their asset life. Treating capital items in this way should ensure that the balance between current and future tariffs is appropriate (so that, broadly, consumers at any moment are paying a fair share of the costs of capital investments). Expensing non-network capex immediately is at odds with this and risks penalizing current consumers for the benefit of future consumers. For this reason we found that treating non-network capex as opex was not in the public interest.

10.60 NIE's main RAB is expensed over 40 years. Capitalizing non-network capex into this RAB would result in it being expensed over a period much greater than its asset life. We therefore provisionally concluded that NIE should create a separate RAB for expenditure on non-network capex and other short-life assets (such as tree cutting—see Section 15). This new RAB should have an asset life of no longer than five years.[9]

Metering capex

Background

10.61 NIE provides metering services to its suppliers. This covers over 800,000 premises in Northern Ireland. Approximately one-third of NIE's domestic customers have Keypad

[9] We note that the replacement cycle for non-network capex is generally five years or less (NIE Statement of Case, pp177&178).

meters, which are prepayment meters and which have grown rapidly in the last decade. The total population of Keypad meters is approximately 270,000.[10]

10.62 The UR proposed a ring-fenced allowance of £20.5 million for metering in RP5.[11] Its proposal was that NIE would only be paid for the volumes of metering work it actually carried out in RP5; it agreed with NIE the unit cost for each type of metering.

10.63 NIE requested that we increase the allowance for metering by £17 million. It said that it was content that the full amount of £37.5 million would be ring-fenced and subject to logging up or down by reference to the actual amounts expended in RP5.[12] Table 10.6 below shows the split of NIE's request, including volumes and costs.

TABLE 10.6 **NIE's metering capex request for RP5**

	Annual meter volumes	*Annual meter costs £'000*	*Unit cost £*	*RP5 total cost (5 years) £'000*
1. Certification	25,000	593	23.72	2,965
2. Recertification	11,000	261	23.72	1,305
3. Commercial recertification	1,000	242	242.00	1,210
4. Keypad recertification	35,000	2,678	76.51	13,387
5. Keypad 'other'	24,500	2,000	81.63	10,000
6. SOSA—other	19,500	542	27.80	2,710
7. Commercial	3,575	929	259.86	4,645
8. Service and support	N/A	250	N/A	1,250
Total		7,495		37,472

Source: NIE; CC analysis.

*Scheduling of ServicePower Appointments—system used by NIE for scheduling customer appointments for metering work (volumes and costs exclude keypad activities included in category 5 above).
N/A = Not applicable.

10.64 NIE's metering capex request in Table 10.6 above can be split as follows:

(a) *Legislation driven (Categories 1–4; £18.8 million in RP5)*. The Certification, Recertification, Commercial Recertification and Keypad Recertification categories are all driven by legislative requirements. Certification involves the replacement of old-style meters which have never been certified. Recertification is driven by a legal requirement to certify meters after a period of time; the certification periods

[10] NIE Statement of Case, paragraph 5.3, p99.
[11] UR Final Determination, paragraph 5.79, p38.
[12] NIE Statement of Case, paragraphs 5.17–5.21, p102.

are prescribed in the relevant legislation and it effectively involves replacement of the meter.[13] The largest request in this area for RP5 relates to Keypad meters, which are required to be certified every ten years.[14]

(b) *Growth in Keypad meters (Category 5; £10.0 million in RP5)*. The Keypad 'other' category mainly reflects the continued expected growth in Keypad meters in RP5. It is reflective of NIE's current activity levels.

(c) *Commercial meters (Category 7; £4.6 million in RP5)*. This category reflects meter installations caused by customers changing tariffs, meter replacements and generator meter asset replacement.

(d) *Routine SOSA metering work (Category 6; £2.7 million in RP5).* This category reflects other[15] routine metering work driven by customer demand and managed through the SOSA scheduling system.

(e) *Overheads (Category 8; £1.25 million in RP5).* Service and support are separately identified metering overheads.

Views of the parties

10.65 In this section we summarize the views presented by the parties. This covers the following areas: metering legislation; forecast volumes; and forecast unit costs

Legislation

10.66 The UR said that the 1998 Regulations came into effect on 1 February 1999 and were closely aligned to the equivalent GB regulations. The legislation requires meters to be certified after a specified time period. In a few cases there is a difference in the certification period for the same type of meter between the GB and Northern Ireland regulations.

[13] The Meters (Certification) Regulations (Northern Ireland) 1998 (the 1998 Regulations).
[14] The relevant legislation actually predates Keypad meters. According to the legislation they have a default certification of ten years.
[15] Other than Keypad appointments; mainly domestic credit meters.

10.67 It said that there were no relevant differences in the manufacture or use of these meters between the two jurisdictions and that it was aware of no reason why some types of meters should have shorter certification periods in Northern Ireland than in GB. For this reason it considered that the certification period for some types of meter (particularly Keypad meters which were more prevalent in Northern Ireland) were not appropriate and should be changed.

10.68 The UR said that in 2005 it agreed with NIE to scale back meter certification for those meters which had been installed before 1 February 1999 and would need to be certified by [✂]. It had intended to promote legislative change to extend the period within which such meters needed to be certified. However, it was unable to obtain agreement to a legislative change being brought forward.

10.69 The UR said that historically the focus of NIE's work had been on replacing meters which had never previously been certified. However, due to the scaling back of the programme it was conscious that over time there would be an increase in meters with expired certification periods. This would particularly be the case from 2011/12.

10.70 The UR said that it was now planning to propose changes to the 1998 Regulations; it expected to take this forward during autumn 2013. This would require the consent of DETI. It said that it proposed to draft the changes required to align the certification periods in the 1998 Regulations with those that applied in GB and to consult on those changes this autumn.

10.71 The UR said that its final proposals for change would be submitted to DETI for its consent before the end of 2013. It said that it could not speculate on the time it might take to get consent but it would have discussed its proposals with DETI in advance;

working to the timetable it outlined it would expect the changes to be effective from early 2014.

10.72 NIE said that the 1998 Regulations came into force in 1999, and as a result it established a certification programme targeting the replacement of uncertified 'dumb' meters with certified meters having equivalent (limited) functionality. This work was driven by a statutory obligation to remove all uncertified meters by [✂].[16]

10.73 NIE said that in 2005 this programme was subsequently scaled back with the agreement of the UR. One of the reasons for this was that evidence suggested that the meters being replaced were accurate and they were being replaced with meters which themselves had limited functionality. NIE said that at this time the UR undertook to make the necessary legislative amendments to reflect this change of policy.[17]

10.74 NIE said that its RP5 submissions to the UR assumed that greater progress would have been made in making the regulatory decisions necessary to roll out smart meters (which could replace uncertified meters). In addition it thought that the outstanding legislative amendments would have been completed before the start of RP5.[18]

10.75 NIE said that it was unclear at this stage when any roll-out of smart meters might begin[19] and that [✂] uncertified meters remained in service.[20] It said that as a result it would be necessary to replace the uncertified meter population as soon as possible and that it could not rely on the roll-out of smart metering as the means of replacing

[16] NIE Statement of Case, p100, paragraph 5.6.
[17] ibid, paragraphs 5.7 & 5.8, p100.
[18] ibid, paragraphs 5.8 & 5.9, p100.
[19] ibid, paragraphs 5.4 & 5.5, pp99&100.
[20] ibid, paragraph 5.8, p100.

uncertified meters in a timely manner.[21] In addition it may face an obligation to recertify Keypad meters, which by default the meter regulations stipulated should be recertified every ten years. NIE said that this was because the 1998 Regulations predated the introduction of Keypad meters and therefore did not specifically prescribe a certification life for Keypad meters, and that any meter type not specifically referred to in the Regulations had a default certification life of ten years.

10.76 NIE said that the impact of certification and recertification was that an additional £17 million would be required to recommence the full meter certification programme that was set aside in 2005: it therefore requested £18.9 million in respect of meter certification and recertification compared with its original BPQ request of £1.9 million.[22] The largest component of this was £13.4 million in respect of Keypad recertification.

10.77 NIE said that it was sceptical as to whether the necessary changes to the 1998 Regulations (to lengthen certification periods) would be transacted by the UR without undue delay. It therefore submitted that any allowance in RP5 should make provision for it to undertake the certification/recertification works required by the current regulations.

10.78 We asked NIE how the UR's proposed legislative change would impact its metering volume forecast. It said that the impact would be limited to Keypad meters; assuming GB certification lives (15 years) the number of Keypad meters requiring certification in RP5 would be [✂] (compared with [✂] if the certification life remained at ten years).

[21] ibid, paragraph 5.11, p100.
[22] ibid, paragraph 5.13, p101.

10.79 We asked DETI how realistic it was to expect the legislative change proposed by the UR to be enacted by early 2014. It said that assuming a standard consultation period for legislation of 3 months and required Ministerial approval, this timeline, while not necessarily unworkable, would be very challenging.

Forecast volumes

10.80 We asked NIE to provide the actual volumes of work which it had completed in each category of metering in 2012/13. NIE provided meter volumes for the period 1 June 2012 to 31 May 2013.[23] These are shown below in Table 10.7.

TABLE 10.7 **NIE meter volumes 1 June 2012 to 31 May 2013**

'000

	Actual volumes	*RP5 annual volume forecast*
Certification	0	25
Recertification	0	11
Commercial recertification	0	1
Keypad recertification	0	35
Keypad 'other'	22	24.5
SOSA—other	32	19.5
Commercial	5	3.6

Source: NIE.

10.81 It can be seen from Table 10.7 that NIE is not currently undertaking any planned certification/recertification volumes. NIE said that these programmes had not yet commenced pending confirmation of the price control arrangements. Actual volumes in respect of the other two categories ('Keypad other' and 'Commercial') broadly reflect NIE's RP5 volume forecast.

Forecast unit costs

10.82 The UR said that as part of the RP5 process, its consultants reviewed NIE's unit costs and believed that they were appropriate based on metering approvals it had assessed during RP4. In addition, it said that additional cost analysis was not

[23] Data was provided for this period since this was when SOSA (post Enduring Solution) went live.

necessary due to the risk-sharing mechanism which it had proposed. We asked NIE if the unit costs submitted in its forecast differed from its recent actual unit costs. We also asked NIE to justify the unit costs contained in its new certification/recertification programme.

10.83 NIE said that its best assessment of recent unit costs for commercial and Keypad metering in 2011/12 and 2012/13 were as follows (see Table 10.8):

TABLE 10.8 **NIE's recent actual unit costs in Commercial and Keypad—Other**

£

	2011/12	*2012/13*	*Submitted in RP5 plan*
Commercial	202	207	260
Keypad—Other	70	74	81.63

Source: NIE.

10.84 NIE said that its submitted commercial unit cost of £[✄] includes an estimated profit element of £[✄].

10.85 Table 10.9 shows the unit cost split between materials and labour for the new programmes of certification/recertification work driven by the 1998 Regulations.

TABLE 10.9 **NIE's metering capex request for RP5**

	Unit cost £	*Labour £*	*Materials £*	*RP5 total cost £m*
1. Certification	23.72	[✄]	[✄]	3.0
2. Recertification	23.72	[✄]	[✄]	1.3
3. Commercial recertification	242.00	[✄]	[✄]	1.2
4. Keypad recertification	76.51	[✄]	[✄]	13.4

Source: NIE.

10.86 NIE said that the following assumptions were built into the unit costs outlined above:

(a) *Certification and recertification (1 and 2 above)*. [✄]

(b) *Commercial recertification (3 above)*. [✄]

(c) *Keypad recertification (4 above)*. [✄]

Our provisional decision on metering and RP5 forecast

10.87 We provisionally decided on a similar approach to metering to that proposed by the UR for RP5 (see Section 5). That is, we will make an upfront forecast, based on volumes and unit costs. However, an adjustment will be made at the end of the RP5 period so that NIE is only paid for the actual volumes of work it completes at a specified unit price.

10.88 To make our forecast we therefore examined NIE's volume and unit cost forecasts for RP5.

10.89 NIE's volume forecast for RP5 is shown in Table 10.9 above. We noted that NIE had made this forecast with the expectation of fulfilling[24] its current statutory duties in respect of the 1998 Meter Certification regulations. We also noted that NIE is currently undertaking no volumes of work in respect of these regulations (see paragraph 10.81). We considered that there were four options available to us in constructing our metering volume forecast:

(a) Accept NIE's volume forecast; NIE's volume forecast for RP5 would amount to a forecast of £37.5 million based on its unit costs.

(b) Adjust the volumes for 'Keypad meters' to reflect the revised volumes that would apply if metering legislation was changed in line with the UR's proposed timetable outlined in paragraphs 10.70 and 10.71. This would result in [✂] Keypad meters requiring certification in RP5 (compared with [✂] if the certification life remained at ten years). This would amount to a £[✂] reduction in the metering forecast submitted by NIE (to £[✂]).[25]

(c) Apply NIE's volumes of recertification/certification from April 2014 only. In this scenario, the volumes of recertification/certification in 2012/13 and 2013/14 would

[24] NIE advised that the volumes of meter certification/recertification planned for RP5 fell short of making provision for all meters for which current certification lives will have expired by the end of RP5.
[25] 93,000 fewer Keypad recertifications at a unit cost of £76.51.

be zero, reflecting the actual outcome in those years. This is because NIE is currently not undertaking any of this work. The impact of this change in volumes would be to reduce NIE's forecast by £7.6 million in the period (£3.8 million in each of 2012/13 and 2013/14).

(d) A combination of (b) and (c) above.

10.90 We were concerned that the legislative timeline proposed by the UR would be very challenging (see paragraph 10.79). Equally, given that NIE is currently undertaking no certification/recertification work we decided it would not be appropriate to make provision for volumes of metering which it had not completed. We therefore provisionally decided that option (c) above was most appropriate. That is, we used NIE's volume forecast, adjusted to reflect its actual (zero) volumes of recertification/ certification in 2012/13 and 2013/14.

10.91 Based on Table 10.8 (see paragraph 10.83) above we provisionally decided that it was necessary to revise the unit costs assumptions in our metering forecast for each of 'Commercial' and 'Keypad—Other'. We did this so that the unit cost assumptions in these categories of metering better reflected NIE's recent actual out-turn costs. In each case our revised unit cost represented the average of the 2011/12 and 2012/13 out-turn unit costs: £205 for Commercial and £72 for Keypad—Other.

10.92 We considered the unit cost assumptions presented by NIE in respect of its new programmes of certification/recertification (see paragraphs 10.85 and 10.86 above). We did not find any reason to adjust the forecast unit costs for these categories of work. Our forecast in these categories therefore reflects NIE's forecast unit costs.

10.93 Our provisional volume and unit cost assumptions result in the annual forecast in Table 10.10 below.

TABLE 10.10 **CC annual metering forecast for RP5**

	Annual meter volumes	*Unit cost £*	*Annual meter costs £'000*
1. Certification*	25,000	23.72	593
2. Recertification*	11,000	23.72	261
3. Commercial recertification*	1,000	242.00	242
4. Keypad recertification*	35,000	76.51	2,678
Annual cost for volumes applying 2014/15—September 2017: £3,774,000			
5. Keypad 'other'	24,500	72.00	1,764
6. SOSA	19,500	27.80	542
7. Commercial	3,575	205.00	733
8. Service and support	N/A	N/A	250
Annual cost for volumes applying 2012/13—September 2017: £3,289,000			

Source: CC analysis.

*The forecast annual volumes in respect of certification/recertification do not apply for the first two years of the forecast. That is, they apply from 2014/15—September 2017.
Note: N/A = Not applicable.

10.94 Putting together the costs for those programmes which will apply for the entire RP5 period (items 5 to 8 above in Table 10.10) with those programmes which will apply only from 2014/15 to September 2017 results in the RP5 forecast shown below (Table 10.11).

TABLE 10.11 **CC metering forecast for RP5**

£'000, 2009/10 prices

	2012/13	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6 months to September 2017*
A. Programmes applying 2012/13—September 2017	3,289	3,289	3,289	3,289	3,289	1,645
B. Programmes applying 2014/15—September 2017			3,774	3,774	3,774	1,887
Total (A + B)	3,289	3,289	7,063	7,063	7,063	3,532
Total for RP5 period: £31,299,000						

Source: CC analysis.

10.95 We note that, based on our provisional decisions on Price Control Design, this forecast will be subject to an ex post adjustment to reflect actual volumes at the unit costs specified in Table 10.10 above.

Meter reading

10.96 In its Final Determination (page 52), the UR proposed an allowance of £13.6 million for meter reading (£2.72 million per year), following a review of salaries and a review of historical data supplied by NIE.

10.97 In its Statement of Case (page 115), NIE set out a meter reading forecast for the RP5 period of £17.9 million or £3.58 million per year. NIE followed this with the statement that 'In the final year of RP4, the Utility Regulator provided an allowance of £3.45m'.

10.98 NIE's Statement of Case focused on criticisms of analysis of meter reading costs carried out by the UR. For instance, NIE disputed the UR's figures on the salary and other employment costs of meter readers, on the number of meter readers required and on central support costs relating to meter reading.

10.99 NIE said that the UR provided 'no justification for the disallowance of the costs allocated to meter reading, which are consistent with the current levels of costs incurred' (Statement of Case, page 120).

10.100 NIE did not explain in its Statement of Case how its forecast costs were consistent with its expenditure on meter reading.

10.101 We looked at historical information on the costs of meter reading activities.

10.102 Costs to NIE of meter reading are reported in the opex BPQ response in the worksheet on 'Dt costs'. These show costs for meter reading of £3.1 million in 2007/08, 2008/09 and 2009/10. However, these figures represent charges from NIE Powerteam to NIE for meter reading. They include a significant profit margin for NIE Powerteam that we do not intend to allow for in our cost assessment.

10.103 Further data on historical meter reading costs is provided in the Excel workbooks accompanying the updated Frontier Economics benchmarking analysis submitted by NIE on 2 August 2013 and 12 August 2013. The reported costs for meter reading for NIE Powerteam were as follows (2009/10 prices):

(a) £2.6 million in 2007/08.

(b) £2.6 million in 2008/09.

(c) £2.8 million in 2009/10.

(d) £3.1 million in 2010/11.

10.104 NIE subsequently provided further information on its historical costs and an explanation of the increases in costs that it has experienced. NIE reports the provided more recent cost information than available in its BPQ response:

(a) £3.3 million in 2011/12.

(b) £3.4 million in 2012/13.

10.105 NIE explained that the cost increases over time were due to the combination of *(a)* a requirement from the UR which meant that it had to increase meter reading visits in the case of Keypad meters, and *(b)* the effect of the introduction in Northern Ireland of the Agency Workers Directive in December 2011.

10.106 We make an allowance of £3.4 million in light of NIE's most recent historical costs and its explanation that the cost increases reflect the impact of greater obligations and legislative change.

Other operating costs relating to Keypad meters

10.107 In its Statement of Case (pages 121 to 123), NIE provided forecasts of £1 million over the RP5 period for various costs relating to Keypad meters. These costs include plastic cards for Keypad meters (£422,000), staff costs (£356,000) and business continuity services (£133,000). NIE said that the UR's Final Determination included an allowance of only £0.7 million which represented a £0.3million shortfall.

10.108 NIE subsequently provided further information on its Keypad opex which linked its forecast to historical expenditure. The main points we take from this are as follows:

(a) NIE said that the number of Keypad meters had increased over time, from about 190,000 in 2007/08 to about 297,000 in March 2013; and

(b) NIE reported that its forecast in its Statement of Case was for £210,600 per year compared with expenditure in 2012/13 of £196,800.

10.109 We propose an annual allowance of 0.21 million in line with the forecast in NIE's Statement of Case.

Overheads for metering and market opening

10.110 As part of our calculation of NIE's 2009/10 indirect costs for the purposes of the GB DNO benchmarking analysis, we have excluded an allocation of NIE's administrative costs and overheads attributed to metering capex, meter reading and market-opening services which GB DNOs would not provide. The value of this allocation was £1.15 million.

10.111 To avoid double counting we made some deductions from this amount. The allowance for metering capex above already includes £0.25 million for service and support costs and we deducted this from the £1.15 million allocation. We made a corresponding adjustment for meter reading of £60,000 based on information provided by NIE about the historical costs we have used in the section above on metering reading expenditure. We have not identified an allocation of NIE's overheads within the cost figures we have used for the Enduring Solution.

10.112 We deducted £0.25 million and £0.06 million from £1.15 million to produce an allowance for metering and meter reading overheads of £0.84 million.

Enduring Solution

Introduction

10.113 In this section we consider the determination of the opex allowance for the Enduring Solution project. A summary of relevant submissions from the UR and NIE is included in Appendix 10.1.

10.114 In summary, Enduring Solution is the IT system introduced to support competition in the retail market. It was intended to aid complete separation of the customer billing processes and legacy IT systems previously shared by NIE and Power NI, and to provide a level playing field for all suppliers, unrestricted switching capability for customers and support of global aggregation for settlement of the all-island wholesale market. The project became operational in May 2012. The opex costs relate to IT support and market-opening costs such as staff costs to perform functions relating to meter reading, billing, switching suppliers, and other market-opening processes. Enduring Solution is an example of new controllable opex, which is not directly comparable with the activities of GB DNOs.

10.115 In its Final Determination, the UR decided on an allowance of £21.5 million for the RP5 period, whereas in its July 2012 submission, NIE had requested £29.4 million. NIE adjusted this to £28.9 million in its Statement of Case to the CC (due to removal of pension costs previously included in the NIE manpower figures).

10.116 Both the UR and NIE expressed concerns about the processes followed in reaching the determination (see Appendix 10.1, paragraphs 2 to 5).

10.117 In reaching our redetermination, we are not directly concerned with the processes that were followed by the UR and NIE; rather we are concerned with determining an appropriate opex allowance given the information that is now available.

Background to Enduring Solution

10.118 As noted in paragraph 2.22, the Northern Ireland Electricity market was opened to supplier competition between 2005 and 2007. In order to facilitate this, and to meet legislative and regulatory requirements for a fully competitive retail electricity market, a new IT system, Enduring Solution, was developed. NIE told us that this was the largest and most complex IT project it had ever undertaken.[26] It was implemented in May 2012.

10.119 NIE said that the Enduring Solution project introduced significant changes to market and business processes. Examples of outcomes were that: it allowed approximately 838,000 retail customers to move between electricity suppliers; it introduced improved functionality for customers; it ensured data integrity for the wholesale and retail markets; and enabled harmonization between the markets in Northern Ireland and the Republic of Ireland.[27] It said that NIE's role was different from GB DNOs' in that NIE was responsible for managing all market processes and the provision and maintenance of all accurate, up-to-date data necessary to support the successful operation of the competitive retail and wholesale electricity markets, whereas in Great Britain responsibilities for these functions were spread across many different industry participants including meter data collectors, data aggregators, suppliers and meter installers. It said that consequently, Enduring Solution was a necessarily complex suite of applications, providing a much wider range of functionality than that required of any GB DNO. NIE said that additional resources were required to support

[26] NIE Statement of Case, paragraph 5.13, p126.
[27] ibid, paragraph 5.18.

these functionally rich, higher cost applications, and as a result, Enduring Solution had created a step change in NIE's operating costs.[28]

10.120 NIE said that examples of these costs included staff costs to deal with 'exceptions' (the term used to describe data errors such as invalid meter readings) and to produce Distribution Use of System (DUoS) bills on an individual site basis for an additional 700,000 sites. Some of these processes were previously handled by Power NI. A variety of new code, reports and systems interfaces were required for the IT systems, all requiring support and maintenance. There was also a large increase in data transactions of various types, potentially producing exceptions, and a very large increase in messages between market participants.[29] NIE said that all of these changes drove increased IT support costs, including infrastructure costs, software licence costs and IT support resource costs. [30]

The UR's determination

10.121 The UR did not set out a detailed explanation in its Provisional Determination or Final Determination documents on how it reached its allowance (of £21.4 million) for Enduring Solution. It noted that NIE had revised its estimates, and was also concerned about NIE's failure to tender separately the Enduring Solution managed service contract. The UR submitted to us several reports undertaken by Gemserv, evaluating NIE's submissions and on which the UR said its determinations were based. The successive Gemserv reports largely assessed cost allowances incrementally as NIE supplied further information and revised its estimates. Gemserv said its remit had been to assess costs as though they were efficiently and competitively procured. Gemserv told us that it was unable to adopt a bottom-up review approach because of issues around ambiguity and supporting information.

[28] ibid, paragraph 5.17.
[29] ibid, paragraphs 5.23 & 5.24, p128.
[30] ibid, paragraph 5.25, p129.

10.122 The UR told us that it was concerned that reaching a determination through assessment of iterations of estimates could carry a risk of bias, because it was in NIE's interests to highlight areas where it identified a need to add further costs, but less so to correct overestimates. However, we note that NIE did propose some downwards adjustments.

Breakdown of Enduring Solution costs

Overall costs

10.123 In July 2012, NIE provided the UR with an updated analysis of forecast costs associated with operation of the new market processes and systems over the RP5 period. It said that cost estimates were refined up to this date, for example because of user acceptance testing indicating the presence of significantly more functionality requiring support than was previously anticipated.[31] Table 10.12 sets out a comparison of NIE's assessment of its opex requirements compared with the UR's Final Determination, broken down by principal cost categories.[32] This incorporates savings on legacy IT systems costs.

TABLE 10.12 **Enduring Solution—NIE's July 2012 forecast versus Final Determination**

£ million

Cost category	*NIE forecast*	*Final Determination*	*Shortfall*
1. Applications Support Resources—SAP	12.5	7.2	5.3
2. Applications Support Resources—non SAP	0.8	1.4	(0.6)
3. Infrastructure Support Resources	2.4	2.7	(0.3)
4. Hardware, Software and Market Entry Costs	7.3	7.3	0.0
5. Outsourced Business Process (BPO) staff	2.9	2.4	0.5
6. Internal costs to support market processes	4.4	3.4	1.0
Total Enduring Solution operating costs	**30.3**	**24.4**	**5.9**
7. Legacy Reductions	(1.4)	(2.0)	0.6
8. Support costs paid by ESB networks	0.0	(1.0)	1.0
Total	**28.9**	**21.4**	**7.5**

Source: NIE Statement of Case, Table 6.17.

[31] ibid, paragraph 5.34, p130.

[32] At a late stage in our process prior to the publication of our provisional determination, we discovered that the UR had wrongly informed NIE that a £385,000 additional application support allowance had been allowed in its determination against non-SAP applications, whereas it was actually allowed against the SAP application. Consequently NIE's submissions have been based on this incorrect data. We have corrected the values in the text and tables sourced from NIE to reflect the allocations the UR intended. The total value of allowances is not affected.

10.124 We note that Gemserv allowed higher costs than requested in some categories because it had taken a hard line against funding Wipro support costs (see Appendix 10.1, paragraph 25). In consequence, the Final Determination can be construed as an allowance as an overall package in the round.

10.125 We now consider each cost category in turn.

Applications Support Resources—SAP

10.126 This cost relates to the outsourced technical resources required to support the main Enduring Solution application (SAP IS-U), to undertake routine maintenance, resolve defects, fix data issues, respond to business and supplier queries and deliver software enhancements.[33]

10.127 NIE said that it outsourced its IT service delivery to Capita Managed IT Solutions (Capita; the contract had originally been placed with Northgate Managed Services (NMS), which was acquired by Capita. We use Capita to refer to both Capita and NMS in this section). The contract had been competitively tendered for a five-year minimum term in 2009. NIE told us that when the managed services contract was awarded, it was understood the new Enduring Solution services would be incorporated into the managed services via a change control. NIE considered that incorporating the Enduring Solution services into that contract was the most cost-effective and low-risk approach, with one organization rather than two providing complete services.[34] It said that the introduction of a second major outsourced IT provider would give rise to additional costs and greater risk as ownership of specific system issues could become blurred and restoration processes extended.[35] It said there would be costs in transferring activities to a new provider (eg new service desk

[33] NIE Statement of Case, paragraph 5.39, p132.
[34] ibid, paragraphs 5.40 & 5.41, p132.
[35] ibid, paragraph 5.44, p132.

resources, costs of terminating existing services, transferring staff to a new provider etc).[36]

10.128 NIE said that it had conducted detailed activity analysis since Enduring Solution had become operational to confirm the final forecast of outsourced technical support costs.[37] NIE said that the provider's average daily rate for SAP applications support was extremely competitive when compared with various benchmark rates.[38] It told us that the allowances included work for minor enhancements going forward but not for major system upgrades or to respond to unforeseen market developments, which would need a separate funding process. NIE also noted that there was uncertainty over how future efficiently incurred costs arising from market harmonization would be treated.[39]

10.129 NIE said that the UR's disallowance of a large part of its predicted costs meant that there would be an entirely inadequate level of funding to allow the retail market processes to operate effectively. It said that at the proposed levels of resourcing, the new SAP IS-U application could not be properly maintained, leading to increasing data and system defects and so impacting suppliers and customers significantly.[40]

Applications Support Resources—non SAP

10.130 This cost category relates to the Capita technical resources required to support the other (non-SAP) Enduring Solution applications, to undertake routine maintenance, resolve defects, fix data issues, respond to business and supplier queries and deliver software enhancements.[41]

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[36] ibid, paragraphs 5.45 & 5.46, p133.
[37] ibid, paragraph 5.52, p133.
[38] ibid, paragraph 5.55, p134.
[39] ibid, paragraph 5.62, p135.
[40] ibid, paragraph 5.68, p136.
[41] ibid, paragraph 5.72, p137.

10.131 NIE said that this was delivered via a change control to the existing NIE Managed Services Agreement with Capita. NIE said that it had been analysing in detail the level of resources that had been required to maintain and service these Enduring Solution systems since it went live, and had challenged these costs to ensure that the required service was delivered at lowest cost.[42] It said that the Capita day rate for support for these types of applications was in the competitive range of benchmarked costs.[43]

10.132 NIE noted that the UR had allowed £0.6 million more for costs than it had requested, reflecting an earlier submission which had been reduced (in part because of cost sharing with ESB).[44] The reason for this higher allowance being maintained (due to reasons outside the scope of this category) is set out in Appendix 10.1, paragraph 25.

Infrastructure Support Resources

10.133 This cost category relates to the Capita technical resources required to support all the infrastructure and network components associated with Enduring Solution, including routine monitoring, maintenance and resolution of defects.[45] NIE said the increased resourcing level was being driven by the large number of new infrastructure components (servers, databases, operating systems and network equipment) introduced to the NIE estate due to Enduring Solution.[46] It said that the daily rate for infrastructure support from Capita was extremely competitive.[47]

10.134 As with the previous category, NIE noted that the UR had allowed more costs than it had requested, reflecting an earlier submission, due to reasons explained in

[42] ibid, paragraphs 5.73 & 5.74, p137.
[43] ibid, paragraph 5.75, p137.
[44] ibid, paragraphs 5.76–5.79, p137.
[45] ibid, paragraph 5.82, p138.
[46] ibid, paragraph 5.85, p138.
[47] ibid, paragraph 5.86, p139.

Appendix 10.1, paragraph 25. NIE also noted that the UR had recognized savings in Applications Support and Infrastructure Support due to sharing of costs with ESB Networks by applying a separate reduction of £1.0 million (see paragraph 10.144) to the overall Enduring Solution allowance, but NIE was not aware how this reduction related to this Infrastructure Support allowance.[48]

Hardware, Software and Market Entry Costs

10.135 This cost category relates to the third party costs associated with hardware maintenance, software licences and other market services such as carrying out an accreditation process for new suppliers as they enter the market.[49]

10.136 NIE said that hardware maintenance and software licence costs were calculated as a standard percentage of the initial implementation costs. Other market services costs were based on historical information and assumptions on the future number of new suppliers entering the market. The UR allowed all the costs that NIE had submitted in its determination.

Outsourced Business Process staff

10.137 This cost relates to the Capita Business Process staff who process exceptions (eg invalid meter readings), correct erroneous transfers (eg invalid registrations that have to be backed out), engage with suppliers and manage meter point data.[50]

10.138 NIE said that these costs related to 19 BPO staff who carried out these activities. It said that pre-Enduring Solution, 22 staff had been required to perform this function, the number having increased with the introduction of full competition generating additional data exceptions and interactions with suppliers. However, NIE estimated

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[48] ibid, paragraphs 5.87 & 5.90, p139.
[49] ibid, paragraph 5.93, p140.
[50] ibid, paragraph 5.99, p141.

that the team size could be reduced because the new IT systems provided greater automation and validation.[51] The UR disallowed £0.5 million of these costs. NIE said that this ignored the 12-fold increase in the volume of transactions and assumed that the new systems would deliver a reduction in resources required. It said that in consequence there would be a significant risk that data errors would not be addressed in a timely manner leading to problems for suppliers and customers. It said it was likely that market service levels would not be met and that overall data quality within the system would degrade.[52]

Internal costs to support market processes

10.139 NIE told us that this cost related to the new NIE staff who were required to operate the competitive market processes. This included the following activities:

- production of distribution use of system bills for suppliers (adding around 700,000 meter points to be billed at individual site level, rather than the previous single distribution use of system bill created from the legacy billing system shared with Power NI);
- production of aggregated supplier data to the all-island wholesale electricity market;
- responding to customer queries, eg concerning supplier switching processes and meter works appointments;
- management of governance arrangements to ensure market process adherence and developments in market design (noting the regulatory requirement to harmonize the Northern Ireland and Republic of Ireland retail electricity markets);
- management of services provided by third party service providers to support the Enduring Solution systems and Keypad prepayment meter infrastructure;

[51] ibid, paragraphs 5.100–5.103, p141.
[52] ibid, paragraph 5.105, p142.

- administration of supplier data queries, connection agreements, and market documentation; and
- resolution of data issues relating to metering fieldwork.[53]

10.140 NIE noted that its role as market operator was unique and so could not be directly benchmarked, for example to confirm optimal resourcing levels. It said that it undertook careful analysis of resourcing requirements and its model was shared with the UR. It reviewed requirements after the project went live and resourcing was re-adjusted. It said that the resources required were settled at 25 FTE staff (compared with 13 pre Enduring Solution). It said that the need for extra staff was driven by the very large increase in DUoS billing, data aggregation (for the wholesale settlement market), to take over data and process issues previously managed by Power NI on the shared legacy billing system, to facilitate an appointment booking system for suppliers, to manage third parties providing IT services, and to deal with market governance arrangements for the harmonized island of Ireland market.[54]

10.141 NIE said that the UR had disallowed some £1 million of costs over RP5, corresponding to seven FTE staff. NIE said that the inadequate levels of staff resources implied by the Final Determination would have a significant negative impact on the provision by NIE of data provision services used for settlement of the wholesale market, as well as on the accuracy of DUoS and retail billing. Further there would be delays in resolving business process exceptions (for example, in metering fieldwork) which would lead to a deterioration of services provided to end customers.[55]

[53] ibid, paragraphs 5.108 & 5.109, p142.
[54] ibid, paragraphs 5.110–114, p143.
[55] ibid, paragraph 5.116, p144.

Legacy Reductions

10.142 This category relates to savings in NIE's existing IT support costs due to certain application and infrastructure decommissioning following the introduction of Enduring Solution.[56]

10.143 NIE said that it had provided the UR with an estimate of savings in November 2011, ahead of detailed decommissioning analysis. It said that it updated the calculations after Enduring Solution went live and submitted its lower estimate in July 2012. However, NIE noted that the UR had adopted the earlier, higher reduction figure in its determination, representing a shortfall of £0.6 million.[57]

Support costs paid by ESB networks

10.144 NIE told us that as part of Enduring Solution, a new market messaging application and infrastructure was implemented for the Northern Ireland market; this was used to process messages between market participants and the market operator. As part of the market harmonization initiative, this subsequently became an all-island solution which was also used by ESB Networks to manage Republic of Ireland market messages. It said that the support costs for the application and associated infrastructure were now shared between NIE and ESB networks.[58]

10.145 NIE said that the UR had disallowed an additional £1 million of costs to recognize the sharing of costs with ESB. It said that cost reductions due to sharing were already built into NIE's submission (in cost categories 2 and 3 above). As the UR's determination in these categories had exceeded NIE's submissions by £1.3 million,

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[56] ibid, paragraph 5.119, p145.
[57] ibid, paragraphs 5.120 & 5.122, p145.
[58] ibid, paragraphs 5.126 & 5.127, p146.

NIE considered that this £1 million reduction represented an acceptable recognition of cost sharing with ESB networks.[59]

Discussion of cost assessment

10.146 In Appendix 10.1 we set out evidence from the UR (and Gemserv) in its assessments of allowances for Enduring Solution and reasons for disallowing some of the costs, and NIE's responses. We concentrate on issues relevant to the areas where the UR's determination is most at odds with NIE's requests, ie categories 1 (Applications Support Resources—SAP), 2 (outsourced business process staff), and 6 (internal costs to support market processes). Our assessment and provisional determination of cost allowances is set out below. We also address the two areas where Gemserv recommended an allowance above NIE's forecast costs.

General observations

10.147 We start by noting observations drawn by NIE and by Gemserv about the Endruing Solution project which help explain the differing perspectives on whether or not the project was only incurring efficient costs. We also look at the actual out-turn costs in the first 12 months since Enduring Solution went live.

10.148 NIE said that it regarded Enduring Solution as a well-managed project (a view the UR agreed with), delivered by a Systems Integrator following a competitive procurement exercise. The Enduring Solution system had been supporting the NI retail market effectively for the past 12 months. It said that the system had created a step change in NIE's operating costs. NIE argued that support costs were based upon a detailed review of activities and they had been validated in the period since go-live. It said that support was being provided at an annual cost of 13 per cent of the original

[59] ibid, paragraph 5.129, p146.

implementation cost which compares favourably with external benchmarks (see Appendix 10.1, paragraph 31).[60]

10.149 In the Gemserv assessments, apart from revisions of cost estimates, attention was particularly drawn to two related concerns. First, NIE had originally developed Enduring Solution as an Oracle product, but then changed to a SAP IS-U platform. Second, the Enduring Solution support and maintenance services were not separately tendered, but rather were incorporated into the existing managed service contract, even though the provider was not necessarily best placed to support the SAP platform. Gemserv told us that it believed some aspects were not efficiently procured.

10.150 NIE provided details of the support costs that had been incurred in the first 12 months since the project went live, see Table 10.13.

TABLE 10.13 **Enduring Solution out-turn opex costs**

£'000, 2009/10 prices

Cost category	*RP 4 Extension Go-live—30 Sep 12*			*RP5 Year 1 1 Oct 12—30 Sep 13*		
	Sub	*Actual*	*Var*	*Sub*	*Actual*	*Var*
ICT						
Applications Support—SAP	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Applications Support—Other	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Infrastructure Support	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Hardware, Software and Market Entry	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
BPO resources	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Subtotal	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Legacy Reductions	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Transitional costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total ICT	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Manpower	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total operating costs	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Source: NIE.

10.151 NIE said that there had been variations in expenditure from forecasts on some elements for the following reasons:

[60] NIE Supplementary Submission, Annex 3, paragraphs 2.1–2.3 and 2.5.

(a) Infrastructure support effort had been lower than anticipated during the first year of operation, due to a reduced level of hardware patching, firmware upgrade and other maintenance activity required for a newly implemented hardware platform. It said that these activities would be expected to ramp up over the course of the RP5 period.

(b) Later than planned purchase of additional SAP licences.

(c) On BPO resources, the need to retain six temporary resources until December 2012.

(d) Lower than submitted manpower costs due to later than planned recruitment of resources who were not in post until early 2013 and some staff turnover. NIE said it did not think it would be able to continue to run with lower manpower than was set out in its submissions.

10.152 NIE told us that the two areas which were proving particularly demanding were in metering resources, because of the loss of synergy with the separation of the legacy systems shared previously with Power NI, and in keeping markets and operations harmonized across the whole of the island of Ireland.

10.153 Given the explanations offered by NIE, we were not able to conclude that the out-turn costs provided persuasive evidence on whether the cost allowances determined by the UR were or were not appropriate.

10.154 The UR also noted that it had allowed substantial transition costs on top of these allowances to support the systems in the first few months of operation (these are not part of our assessment of ongoing support costs).

Applications Support Resources—SAP

10.155 Material from the parties explaining the derivation of the UR's allowance for this category, and the parties' submissions on the reasons why these costs should or should not be allowed, are set out in Appendix 10.1.

10.156 In assessing an appropriate allowance for SAP applications support, we note that Gemserv was asked to evaluate costs against an efficient company procuring services efficiently. This is clearly a principle working in the interests of consumers and deterring any inefficiencies and forms a suitable default assumption in most cases. We also agree that the change in systems from Oracle to SAP and the consequence that NIE found it had to allow Capita to seek further resources to support SAP, are not examples of the most efficient practice. This is likely to have resulted in NIE facing total costs higher than would be those had it originally tendered for a SAP product with a support package. In retrospect, it would have facilitated the delivery of Enduring Solution had contracts allowed for change and adjustments in the context of developments that had arisen. Nonetheless we also note that the project has been successfully delivered and now appears to be working well.

10.157 However, while we accept this, we also think it is informative to consider whether decisions taken at the time were ones that a reasonably efficient company could be expected to have taken, without the benefit of hindsight.

10.158 In that light, we have not been persuaded that NIE's original decisions to adopt an Oracle solution, nor to tender for a single IT services delivery package, represented poor decisions at the time they were taken. Similarly, we were not persuaded that NIE made a poor decision when it decided to change from Oracle to SAP following the acquisition by ESB. In that circumstance, we did not consider that it was an inappropriate decision not to separately tender for SAP support given the termination costs that would be incurred, nor the practical difficulties of then having two different IT service delivery providers. We note that Capita tested the market to some extent by comparing Wipro with two other potential providers. This mitigates to some extent against Gemserv's concern that Wipro appeared to have been in a very strong position when negotiating terms with Capita and NIE.

10.159 We are concerned that elements of NIE's cost projections going forward do not seem to fully reflect efficient practice. In particular, we are surprised by the slow rate of efficiency gain envisaged. For example, while we accept that when a new project is rolled out, one would want support to be available locally, it does appear that NIE has been slow to endorse the cost savings which might arise from progressive offshoring of most support once the system is established. [✂] Indeed, we think that reductions might even be achieved more rapidly than allowed for in the UR's determination.

10.160 We have some concerns about the approach the UR adopted in assessing costs. The nature of this project meant that benchmarking costs was challenging, although we acknowledge that there were no other practicable ways to test NIE's cost and resource projections. While it was sensible procedurally for Gemserv to assess NIE's revised submissions on an incremental basis and only accept these where well evidenced, it does implicitly seem to give greater weight to NIE's initial estimates and has resulted in some questionable decisions, such as rejection of some of NIE's projected reductions in costs.

10.161 Given these competing considerations and the very limited availability of reliable benchmarking information, we consider that determining the appropriate allowance rests to a considerable extent on judgement. Our concerns particularly relate to the apparent failure of NIE to fully exploit opportunities for cost reductions over the life of RP5.

10.162 We therefore conclude that while a higher allowance should be set for the first year, somewhat higher than the UR's determination, but not fully meeting NIE's requests because of the limitations in the processes it had followed, this allowance should then reduce because of the potential for efficiency gains.

10.163 We have provisionally decided that an additional allowance of £2.5 million over RP5 be provided: £900,000 in 2012/13, declining by £200,000 each year so that there is an additional allowance of £100,000 in 2016/17.

10.164 This adjustment means that while the total value of the SAP support allowance is increased by £2.5 million to £9.68 million, it declines at a faster rate than in the UR's determination. From a 2012/13 allowance of £2.76 million it declines each year by –15.7 per cent, –19.2 per cent, –21.9 per cent and finally (2015/16 to 2016/17) –14.2 per cent.

Outsourced business process staff

10.165 The UR's and NIE's submissions in relation to the assessment of allowances for this category of costs are set out in Appendix 10.1.

10.166 This category represents a forecast where there is uncertainty over how future levels of activity will develop given the benefits of new systems but potentially increasing demands. We note that Table 10.13 shows a small overspend in this category but due to the temporary retention of transitional staff.

10.167 Little persuasive justification has been offered by either party in relation to the appropriate staffing allowance, particularly in how it will develop over time. The lack of clarity over Gemserv's assessment and lack of robust evidence to support NIE's projections hamper assessment. We find it surprising that costs are not projected to fall over time given that we would expect queries and data inconsistencies to decline as the systems bed in.

10.168 Taking note of probable long-term impacts on costs, we conclude that some dis-allowance against NIE's projections is appropriate. We conclude that an allowance of £2.65 million is appropriate.

Internal costs to support market processes

10.169 The UR's and NIE's submissions in relation to the assessment of allowances for this category of costs are set out in Appendix 10.1.

10.170 The precise staff numbers that have been disallowed by Gemserv as set out in its July 2012 report do not appear to directly correspond to the costs identified in NIE's final submission. However, in relation to the staff roles that are identified, we first note the disagreement between the UR and NIE on whether NIE requires staff to deal with customer queries. In our view, the UR's position that suppliers rather than NIE should be the point of customer contact is a reasonable and practical policy. While NIE may wish to maintain helpful relations with the public, they are unlikely to be direct customers of NIE, and this policy would seem to help perpetuate customer confusion. Therefore we accept the UR's view that such support should not be funded.

10.171 In relation to the other identified functions, NIE's assertion that Gemserv had failed to undertake robust analysis to support its opinion seems to be unpersuasive. Its role was to review the legitimacy of NIE's applications, not to produce an alternative submission. It has provided reasons for its rejection of certain resourcing, particularly that there is unlikely to be a need for specialist metering electricians for SEM faults.

10.172 We have not resolved the discrepancy on the other resources. However, in the absence of other evidence, we conclude that the UR’s allowance in this category is appropriate.

Other aspects

10.173 As noted in paragraphs 10.132 and 10.134, in the case of non-SAP applications support resources, and infrastructure support resources, the UR’s allowances exceeded NIE’s request by £0.6 million and £0.3 million respectively. This was because Gemserv had adopted a general policy of not revising its original cost allowances unless the reasons for this had been well supported by NIE (even where this was for a reduction), and because it was taking a view of allowances in the round where it had taken a hard line against funding Wipro support costs.

10.174 Our assessment of the SAP Applications Support Resources is intended to cover reasonable costs, and so other costs do not need to be viewed in the round to compensate for this. We also consider that the threshold of proof to accept a revision of costs from NIE will be different where it is reducing a cost estimate. In the absence of reason to believe NIE’s cost forecasts were inappropriate, we make a further £0.9 million reduction in cost allowances for these two categories.

10.175 We note that the items considered above are those where there are substantive disagreements between NIE and the UR. We reviewed the other areas of the determination but did not identify reasons to consider that the allowances may be inappropriate.

10.176 We have made an explicit adjustment in the allowances for expected gains in productivity on SAP applications support. The numbers already take account of the adjustment made by Gemserv to neutralize the effect of the RPI-X term. We have allowed this so as to have the effect of offsetting the 1 per cent productivity adjustment we have applied generally to costs.

10.177 Gemserv said it understood that NIE had incurred high transitional costs over the initial operational period. With this in mind, and the proposed disallowance of the new Wipro cost line, it recommended that an additional short-term allowance should be made under a separate D_T term adjustment. We have not considered the suitability of these allowances in this section as we consider that they relate to the original implementation of the project rather than ongoing operational expenditure support.

Allowances for 2012

10.178 Our determination covers relevant costs from 2012. These allowances cover the period where NIE raised concerns on unresolved RP4 issues (see paragraphs 14.5 to 14.10). These allowances are set as up front allowances, and so are not adjusted for the actual incurred costs shown in Table 10.13.

Our provisional determination on Enduring Solution

10.179 The allowances we have provisionally determined for Enduring Solution are shown in Table 10.14, with the UR's Final Determination (from Table 10.12) for comparison. These allowances cover the five-year period April 2012 to March 2017, as shown in Table 10.15. The final year allowances can be adjusted pro rata for our proposed RP5 period of 5.5 years.

TABLE 10.14 **Enduring Solution—the CC's provisional determination**

Cost category	CC provisional determination	UR Final Determination
		£ million
1. Applications Support Resources—SAP	9.7	7.2
2. Applications Support Resources—Non SAP	0.8	1.4
3. Infrastructure Support Resources	2.4	2.7
4. Hardware, Software and Market Entry Costs	7.3	7.3
5. BPO staff	2.7	2.4
6. Internal costs to support market processes	3.4	3.4
Total Enduring Solution operating costs	**26.3**	**24.4**
7. Legacy Reductions	–2.0	(2.0)
8. Support costs paid by ESB Networks	–1.0	(1.0)
Total	**23.3**	**21.4**

Source: CC.

TABLE 10.15 **Enduring Solution—the CC's provisional determination, allowances by year**

Year	*CC provisional determination £m*
2012/13	5.15
2013/14	5.00
2014/15	4.67
2015/16	4.35
2016/17	4.11

Source: CC.

Connection charges funded through RAB

Background

10.180 This expenditure is the capital cost of connecting new domestic and smaller businesses to the electricity network. Until 1 October 2012, new domestic and smaller businesses connecting to the network received a subsidy which meant that they were only required to pay 60 per cent of the cost of their new connection. The remaining 40 per cent, a subsidy, was capitalized into the RAB and effectively paid for by all NIE's customers.

10.181 This subsidy was removed so that for all applications for connection made from 1 October 2012, the full cost of a connection will be paid by the applicant. However, where prior to 5 April 2012 (the date of publication of the UR's decision to remove the subsidy) NIE has made a connection offer to an applicant under the previous charging regime (ie with a 40 per cent subsidy) and that offer has been accepted, NIE must honour the terms of that connection offer. It is not uncommon for connection works associated with developments to be completed some four or five years after the date on which the offer was accepted. Moreover, under transitional provisions agreed by the UR, where NIE received applications for connection after 5 April 2012 but prior to 1 October 2012, and offers were made prior to 1 January 2013, the applicant will receive the subsidy as long as the connection is completed by 1 October 2014.

10.182 NIE requested an allowance of £15.8 million for new connections costs for RP5 (£17.4 million including RASW costs). RASW costs are the costs associated with the introduction of RASW legislation; the costs cover permitting, fixed penalty notices, overrun charges and additional labour costs.

10.183 The UR accepted NIE's New Connections request, with the amount being ring-fenced so that only NIE's actual spend was passed through to consumers. It envisaged that any over or under spend against the connections expenditure capex forecast would therefore be adjusted on an ex post basis to reflect out-turn expenditure. NIE agreed with the UR that its connections allowance should be logged up or down by reference to the amounts actually expended by NIE during RP5.[61]

Views of the parties

10.184 NIE said that its forecast for RP5 reflected the phasing out of the new connections subsidy, with costs falling from £7.5 million in year 1 to £0.8 million in year 5.[62]

[61] NIE Statement of Case, Chapter 5, paragraph 5.22 (p102).
[62] ibid, p424. In addition, RASW costs fall from £0.8 million to £0.1 million.

10.185 We asked what net connection costs out-turned at in 2012/13 and NIE said that this was £5.0 million. When compared with its forecast of £7.5 million for 2012/13 this represents a shortfall of 33 per cent.

Our provisional decision on new connections costs and RP5 forecast

10.186 We provisionally decided that the cost pass-through of these items was not against the public interest (see Section 5). This is because the risk of excessive costs should be mitigated by effective regulation of connections charges and also because the arrangement is a temporary one (as the subsidy cost phases out). We therefore make a forecast for the period but we note that this will be adjusted on an ex post basis to reflect actual expenditure on net connections.

10.187 Given the difference between NIE's forecast for net connections and the out-turn, we considered that it was appropriate to make a downward adjustment to NIE's net connections forecast of 33 per cent in year one and in each subsequent year. This is because the out-turn in 2012/13 suggests that the path of new connections will be shallower than originally forecast by NIE.

10.188 We have also excluded from our forecast any connections following October 2014. As a result we further reduced by 50 per cent our forecast for the year ending March 2015. This is because the UR's decision in respect of the new connections subsidy is clear that it will not apply to any new connections after 1 October 2014:

> In approving the removal of the connections subsidy for domestic customers and small businesses the Utility Regulator determines that offers for connection requested before 1 October 2012 and made

before 1 January 2013 will receive this subsidy as long as they are completed by 1 October 2014[63]

10.189 In addition, we note that RASW legislation has not yet been implemented in Northern Ireland, although NIE has said that it is expected to be implemented within RP5. The UR told us that it had recently spoken to the Street Works Manager in the Roads Service who had informed it that the outstanding elements of the RASW legislation, particularly with respect to fixed penalties and to the fees for the permit scheme, had been reviewed by DETI this year. It said that the Manager had confirmed to the UR that there were no plans to enforce these requirements from the legislation in the foreseeable future.

10.190 We asked DETI whether RASW legislation was likely to be implemented during RP5. DETI told us that the Department for Regional Development (DRD) was no longer actively progressing the RASW proposals in Northern Ireland, although the primary legislation remained in place and DRD reserved the right to review the position in the future. DRD said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present. We therefore made no allowance for RASW legislation in our forecast.

10.191 This results in the following forecast (Table 10.16) for NIE's net connections costs.

[63] www.uregni.gov.uk/uploads/publications/Electricity_connection_policy_decision_paper_-_April_2012.pdf.

TABLE 10.16 **Net connections forecast for RP5**

						£ million
2009/10 prices	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6 months to September 2017*
Net connections costs	5.0	2.5	0.8	0.0	0.0	0.0
RASW costs (net connections)	0.0	0.0	0.0	0.0	0.0	0.0
Total net connections capex	5.0	2.5	0.8	0.0	0.0	0.0

Source: CC analysis.

10.192 Our total forecast for net connections costs (including RASW costs) in RP5 is therefore £8.3 million. This compares with NIE's forecast of £17.4 million. The difference in the forecast is explained by: a cut to the forecast we have made to reflect a shallower path of actual new connections; the exclusion of RASW costs; and the exclusion of any new connections forecast beyond October 2014.

Storm costs relating to atypical severe weather

Background

10.193 This category of costs covers major storm events. These are currently classified by NIE and the UR as severe weather events costing more than £1 million, although both parties agreed that this definition should be redefined.

10.194 In our benchmarking analysis (see Section 8), we used data for GB DNOs on costs relating to IMF&T. These are reported under the wider cost category used by Ofgem of 'network operating costs'. We do not include the costs reported by GB DNOs under another element of network operating costs which is 'Severe Weather—Atypical'. Ofgem defines an exceptional severe weather event in its regulatory reporting rules, with reference to a threshold number of incidents caused by the event which is specified separately for each company.

10.195 An allowance for NIE set on the basis of either the GB DNO benchmarking analysis or the historical level of IMF&T costs we have used for NIE would not include provision for costs of atypical severe weather events (as defined by Ofgem) or the type of extreme event such as the March 2010 ice storm in Northern Ireland (we have assumed that Frontier's exclusion of the costs attributed to the March 2010 ice storm (only) is made on the basis that only this would qualify under 'Severe Weather—Atypical' in Ofgem's reporting framework). We therefore considered how this category of costs should be treated in our determination.

Views of the parties

10.196 NIE did not make a request for an ex ante allowance for major storm events. It proposed instead that storms that gave rise to costs above £1 million should be subject to a force majeure arrangement under which the UR could make adjustments to NIE's maximum regulated revenue during the price control period to allow it additional money to cover the costs it incurs in these circumstances.

10.197 The UR also proposed regulatory arrangements involving the potential for ex post adjustment, determined by the UR, to provide NIE with additional revenue to cover the costs of atypical storm events.

Provisional decision on storm costs relating to atypical severe weather

10.198 Under both the UR's and NIE's proposals major storm events would be passed straight through to consumers. We did not favour such an arrangement for two reasons. First, we believed that wherever possible we should avoid cost pass-through which could expose consumers to unnecessarily high costs: we want to give NIE incentives to mitigate costs. Second, we found that the proposed definition of a major storm that would trigger cost pass-through (an event costing more than

£1 million) could give rise to perverse incentives when considered alongside our treatment of normal or typical storms (and other expenditure more generally).

10.199 This is because our benchmarked indirect cost allowance includes an allowance for typical storms; 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 would face a powerful incentive to increase the cost of storm events to the £1 million pass-through threshold. We found that such an arrangement would not be in the public interest and we therefore decided that it was appropriate to set an ex ante allowance in this area despite the inevitable difficulties in setting the level of the allowance.

Severe weather allowance for RP5

10.200 We recognized that setting an ex ante allowance for severe weather involved a substantial degree of judgement. Such events are rare and costly. We first considered GB DNO data on gross costs for severe atypical weather. This data is shown below in Table 10.17.

TABLE 10.17 **GB DNO gross costs for severe atypical weather events, 2009/10 to 2011/12**

	2009/10	*2010/11*	*2011/12*
GB DNOs reporting cost in this category	0	0	1
Gross costs reported (£m)	0	0	5.3

Source: GB DNO data provided to CC by Ofgem.

10.201 It can be seen from Table 10.17 that over the three years of our data 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 (of £5.3 million). Over the three-year period of our sample the simple average cost per GB DNO was £126,000; for 2011/12 the simple average cost per GB DNO was £378,000.

10.202 We noted that Ofgem defined atypical severe weather events as one-in-20-year events.[64] Our allowance for typical storm costs, based on GB DNO costs, will not cover these costs, so the Ofgem definition is relevant. Taking the atypical severe weather event cost reported in 2011/12 (of £5.3 million) as being a one-in-20-year event implies that an annual allowance of around £265,000 would be appropriate. We noted that this number would be higher or lower depending on the magnitude of the event being considered. For example, an event costing £1 million (the lowest-cost severe storm using the current UR/NIE definition) would imply an annual allowance of £50,000.

10.203 Based on paragraphs 10.201 and 10.202 we considered that a plausible annual allowance for severe storms was in the range of £50,000 to £378,000. We provisionally decided on an allowance of £200,000 a year, or £1,100,000, for RP5.

Costs associated with aggregated generator units

10.204 We included an additional allowance of £33,000 per year for operating costs associated with the arrangements for aggregated generator units (AGU). In a report submitted by NIE, Frontier Economics explains as follows:

> The AGU arrangements were established to facilitate a collection of small customer-side stand-by generators (geographically dispersed across NI) trading energy in the Single Electricity Market. NIE provides support for these market arrangements through its meter data collection and registration functions. These functions are not the responsibility of network operators in GB ...

10.205 Our annual allowance of £33,000 is based on NIE's reported costs in 2009/10 in its opex BPQ response.

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[64] www.ofgem.gov.uk/ofgem-publications/46574/dpcr5glossaryoftermsclean1.pdf, p10.

Revenue deducted for customer contribution to O&M charges

10.206 For generation connection and in some cases for some elements of demand connections, NIE charges in connection charges for capitalized O&M costs.[65] These costs are calculated on the basis of a rate of 1.2 per cent of the asset construction cost, and a default notional period of 20 years. Using a discount rate of 4.1 per cent, the resulting capitalized O&M charge is about 16 per cent of the asset value.

10.207 Without some form of adjustment, NIE would be funded twice for an element of its O&M expenditure, since we have made a separate allowance for NIE's indirect costs and its costs for IMF&T.

10.208 NIE's submissions set out forecasts of expected costs but not revenues that might offset these costs. We made an approximate estimate of the annual revenue from customer contribution to O&M charges as part of our cost assessment. This comes to £0.6 million per year.

10.209 Our estimate is explained as follows. To estimate the total incoming revenue attributable to this element of connection charges, we took the relevant total amount of capital contributions from connection charges to be £7.8 million a year. This is the amount that was released to the profit and loss statement in 2009/10, and it therefore reflects an average level of past capital contributions from customers. We assumed that half of the assets constructed attracted a capitalized operation and maintenance charge of 16 per cent. Our estimate of the annual income attributable to the release of capitalized operation and maintenance charges of £0.6 million a year is calculated as an allocation of the amount of capital contributions above (£7.8 million) according

[65] NIE 'Statement of charges for connection to the Northern Ireland Electricity distribution system. Effective from 1 October 2013', p16.

to an estimate of the proportion of those capital contributions that are for O&M charges.[66]

Revenue raised in cases of illegal abstraction of electricity

10.210 In 2009/10 NIE received around £425,000 in revenue arising from charges or money recovered in cases of illegal abstraction of electricity from its network.

10.211 We considered whether we should adjust our cost allowance to take account of the likelihood that NIE continues to benefit from such revenues in the future, which could help offset its expenditure requirements.

10.212 However, we do not make such an adjustment. As set out in Section 6, we propose that there is a mechanism within the price control to share 50 per cent of any revenues raised by NIE in cases of illegal abstraction of electricity with consumers, through reductions to allowed revenue. We do not consider any further adjustment appropriate as it could dilute the financial incentive on NIE to take action in cases of illegal abstraction.

Research and development

10.213 NIE has sought £2.5 million over the RP5 period for R&D. No such allowance was provided in the UR's Final Determination for RP5.[67]

10.214 In Great Britain, Ofgem has developed a complex set of regulatory arrangements to provide DNOs with funding for R&D and other innovative activities. This includes the Low Carbon Networks Fund (LCNF) through which DNOs can bid for funding which is paid for through charges to consumers.

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[66] This proportion is calculated as (0.16*0.5) / (0.5+(0.5*1.16)) which reflects the assumption that 50 per cent of connections attract a capitalized charge on top of the asset value and 50 per cent just reflect the asset value.
[67] NIE Statement of Case, p159.

10.215 NIE told us that the costs incurred by GB DNOs in relation to the LCNF and other innovation-funding schemes were not included in the DNO's core regulated costs and that, absence a specific allowance, our benchmarking analysis of indirect costs and IMF&T costs would not provide funding for NIE to carry out R&D.

10.216 NIE provided some information on the R&D it expected to undertake in its Statement of Case,[68] which we have considered as part of our assessment. However, NIE did not provide detailed information on how it proposed to spend an R&D allowance and why this expenditure was likely to be in consumers' interests.

10.217 We do not accept that NIE would do no R&D or innovative activities if we made no allowance for it. For example, the use of benchmarking analysis in price control reviews provides some incentives for improvements that can help reduce costs. Further, NIE would have the opportunity to propose innovative investment projects, on which it could earn a return on capital, as part of its investment plans at future price control review.

10.218 However, we accept that NIE might not face the same pressures to innovate as a firm in a competitive market. An allowance for R&D could help increase NIE's innovative activity. Even so, compared with firms in a more competitive market or commercial environment, NIE would not face the same degree of market discipline and feedback processes that help direct R&D and innovative efforts to productive uses.

10.219 We considered two options:

(a) No specific additional allowance for R&D.

[68] ibid, pp159–162 and 250–252.

(b) A special allowance for R&D of £0.5 million per year on a 'use it or lose it' basis (ie an allowance of £0.5 million per year, but with a provision for a future revenue adjustment to claw back any amount of this allowance that is not spent on R&D). Under this approach NIE would report to stakeholders annually, through a publication on what it has done with the R&D allowance.

10.220 We have decided that, on balance, the public interest is best served by option (a), under which we provide no additional allowance for R&D. We were not confident that such an allowance would be cost-effective for consumers.

Road and street works legislation

10.221 In its Statement of Case NIE said (pages 156 and 157) that it would incur additional operating costs associated with new RASW legislation once the Street Works (Amendment) (Northern Ireland) Order 2007 had been brought into force. NIE said that these costs would relate to opex and capex and could relate to:

(a) overrun changes where work exceeded the required limit;

(b) permit schemes in relation to which NIE is required to pay to carry out work within specified areas; and

(c) the additional costs of directions to NIE as to when work could be carried out (eg at weekends or after working hours).

10.222 NIE submitted opex forecasts of £2.1 million in relation to RASW legislation.

10.223 As discussed in paragraphs 9.75 to 9.79, over the course of our inquiry we received further information on the proposed changes to RASW legislation.

10.224 DETI told us that it was no longer actively progressing the RASW proposals, although the primary legislation remained in place and it reserved the right to review the position in the future. It said that there was no longer a robust business case for introducing such a scheme and that there were no plans to review that decision at present.

10.225 We provisionally make no upfront allowance in relation to additional costs that NIE may incur as a result of new RASW legislation. If such costs do arise, NIE would be able to seek a change to the revenue restriction in its licence conditions through the change of law provision.

10.226 NIE told us that given the uncertainties regarding implementation of the RASW legislation, NIE would be content with this approach.

Enhanced regulatory reporting requirements

10.227 We have not included any additional allowance for changes in NIE's regulatory reporting requirements.

10.228 In its Statement of Case, NIE said that it would incur additional costs relating to the UR's proposed reporter function which were not recognized by the UR (page 158). Since we are not supporting the specific proposals made by the UR for a new reporter function NIE will not incur these costs and we provisionally make no allowance for them.

10.229 We proposed that NIE should report costs in line with the Ofgem regulatory reporting arrangements for GB DNOs.

10.230 We recognize that changes in the regulatory reporting obligations for NIE could give rise to material increases in indirect costs.

10.231 The GB DNO indirect cost data that we used for benchmarking analysis will reflect the costs DNOs in GB already incur as part of their regulatory reporting under Ofgem’s RIGS framework.

10.232 NIE told us that in response to ongoing reporting costs, it accepted that the GB DNO benchmark included the costs incurred by the GB DNOs in reporting under their RIGs. NIE said that since the GB DNO reporting processes were well established it did not consider that the GB DNO costs would reflect the initial set-up costs to develop the necessary processes and systems to capture additional data. NIE identified the following tasks which it said would give rise to additional costs not captured in the GB DNO cost benchmark:

(a) Design and alignment of cost collection processes and systems to reflect the Ofgem definitions.

(b) Adjustment to existing project management processes to record costs on a per-asset type basis rather than a per project/site basis.

(c) Introduction of additional time recording processes and systems to assist in cost collection and allocation.

(d) Completion of upgrade of Grade 1 asset system for OHL.

(e) Additional reporting functionality to be developed to existing Maximo system for recording assets.

(f) Significant upgrade to SAP systems and processes to record data in required formats.

(g) Development of systems and processes to collect load and health indices.

(h) Roll-out program to educate the business of new reporting requirements and processes.

10.233 NIE had not provided us with an estimate of these costs in time for our provisional determinations. The scope of the GB regulatory reporting framework that NIE will be required to report to has not yet been determined.

10.234 We have not included any additional allowance for regulatory reporting costs as part of our cost assessment in our provisional determinations.

10.235 We propose to review any submission from NIE and other stakeholders on a cost adjustment for regulatory reporting set-up costs in reaching our final determinations. As part of their review we will consider the extent to which any proposed cost adjustments are supported by evidence of incremental cost impacts on NIE that are not captured in the GB DNO cost benchmarks. We will also consider the extent to which an adjustment is appropriate given the possibility that although the GB DNO benchmarks may not include regulatory reporting set-up costs that NIE will face, they may include some other costs that NIE does not face.

Information leaflets and advertising in relation to ESQCR

10.236 NIE forecast £0.2 million over the RP5 period 'for the production of information leaflets and advertising in order to meet NIE's obligations under the ESQCR legislation' (Statement of Case, page 159). We do not propose an adjustment to our cost assessment. The GB DNOs faced obligations in relation to ESQCR legislation in the years covered by our benchmarking analysis. We would expect any costs relating to information leaflets and advertising to be included within a GB DNO's indirect costs.

Workforce renewal

10.237 In its Statement of Case, NIE requested £4.9 million for workforce renewal over the RP5 period.

10.238 NIE said that at its last price control review Ofgem provided a separate allowance for workforce renewal of £173 million.[69] We have confirmed this amount in Ofgem's final proposals: it is the total across 14 GB DNOs for the five-year period in 2007/08 prices.

10.239 Ofgem's glossary for its current price control review defines workforce renewal as follows:

> Workforce renewal involves the recruitment of training of new staff and upskilling of existing staff to replace leavers from the operational workforce (roles meeting definitions of 'craftsperson', 'engineers' and 'non-engineering roles'). It includes learner costs associated with both classroom and new recruits and upskilling. It includes trainer and course material costs associated with classroom training. It also includes training centre and training admin costs associated with new recruits and upskilling. It includes the recruitment costs associated with operational trainers.

10.240 NIE explained in its Statement of Case why it expected cost increases relating to training and recruitment which fell under the category of workforce renewal.

10.241 In its RP5 proposals, the UR did not include an allowance for workforce renewal. The UR said the following in its submissions to us (UR-3, page 5):

> Given the state of the economy in Northern Ireland (and in the wider UK and in the Republic of Ireland), it is difficult to understand why labour costs ought to increase substantially over the RP5 period. NIE T&D suggested that the consequence of not allowing it to increase spending on wages was that skilled staff would leave to take up employment

[69] NIE Statement of Case, p147.

elsewhere, but NIE T&D was unable to provide convincing evidence to support that proposition. Moreover, to the extent that the additional workforce opex costs anticipated by NIE T&D were associated with the extraordinary capex programme that it had proposed, they would not in fact be likely to be incurred in light of the findings that we reached in relation to capex (as to which see our paper on capex). That is something that can be revisited during the course of this inquiry if the Commission takes a different view of the amount of capex that is required.

10.242 Our assessment of these issues has started from the perspective that the costs that GB DNOs experienced relating to workforce renewal in 2009/10 will be reflected in our benchmarking analysis.

10.243 NIE suggested that this would provide an insufficient allowance because 'the GB DNOs were ramping up their expenditure on [workforce renewal] during 2009/2010 (the last year of DPCR4) but that expenditure had not reached the level embodied in the DPCR5 allowances'.

10.244 Our view is that workforce renewal costs are included in our benchmarking analysis and that it would amount to double counting to add in NIE's forecast from its Statement of Case of £4.9 million over the RP5 period.

10.245 However, we accept that if there have been significant increases in workforce renewal costs across the UK then our allowance may underestimate NIE's costs in relation to workforce renewal.

10.246 NIE has suggested that we could seek data from Ofgem to examine how costs specifically related to workforce renewal have changed over time.[70] We have not done so. We would be reluctant to make an adjustment to our cost allowance for NIE on the basis that one specific category of costs has increased over time. Other categories may have decreased. Such an approach seems asymmetric.

10.247 We do not make an adjustment for workforce renewal. We have not identified a sound basis on which to make such an adjustment in light of the issues above.

10.248 We should highlight that there are other areas of our cost assessment where the lack of information to determine a reasonable adjustment has worked in NIE's favour.

10.249 For instance, we have included a separate allowance for Enduring Solution. However, the indirect cost benchmarking analyses submitted by NIE and the UR recognized that some element of the costs of Enduring Solution were likely to cover activities that are carried out by GB DNOs. In this respect, adding a separate allowance for Enduring Solution to cost benchmarks from analysis of GB DNOs may include an element of double counting. NIE has suggested that the extent of overlap may be in the region of £0.13–£0.19 million,[71] while the UR has suggested that a figure of £500,000 is conservative. Neither party provided an explanation of their figures and we found it an area that it was difficult to come to a reasonable decision on and have made no explicit adjustment.

Distribution service centre: additional operating costs

10.250 NIE sought an allowance of £0.8 million over the RP5 period for additional opex relating to its distribution service centre which it said arose from the proliferation of renewable generation connecting to the system (Statement of Case, page 169).

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[70] ibid, p6.
[71] ibid, p188.

These costs were based on NIE's view that it needed to recruit four additional staff, three within the SCADA section and one control engineer. NIE reported that the UR included no such allowance as part of its RP5 proposals.

10.251 This aspect of NIE's submissions raises similar issues to workforce renewal, albeit with a smaller level of costs forecasts by NIE:

(a) Costs related to NIE's distribution service centre fall under the Ofgem category of indirect costs and the allowance we make based on our benchmarking analysis should already reflect such costs.

(b) NIE submitted that increases over time in the level of distributed generation connections meant that its costs would be higher than those implied by benchmarked costs from 2009/10.

10.252 Given the relatively small scale of the costs forecast by NIE (around £160,000 per year) and the difficulties we face in estimating the incremental impact of (b), we have not made an adjustment to our cost assessment.

PAS 55

10.253 In its Statement of Case, NIE sought an additional £0.1 million to cover the costs of PAS 55 certification. We have not included a separate allowance for PAS 55. This does not meet the criteria set out at the start of this section and we have not identified any other reason to include it.

10.254 NIE has submitted a further argument why a specific allowance for PAS 55 certification is appropriate:

> Throughout the price review UR placed considerable emphasis on PAS 55 and included an allowance of £0.1 million in its FD in line with NIE's submission for costs associated with gaining accreditation in RP5. NIE

took this as a de facto obligation, and proceeded in good faith with the certification process, even though the price control was not settled at that point. As CC will be aware, PAS 55 certification has now been achieved - in advance of the RP5 price control taking effect. Consultancy costs incurred to date and to be incurred over the next 12 months (associated with post certification surveillance audits) are expected to amount to c £0.1 million. Their recovery should be provided for in the RP4 price control modifications for the period 1 April 2012 to 30 September 2014.

10.255 We do not accept this argument. We do not consider that NIE is entitled to revenue to cover the costs it incurred obtaining PAS 55 certification by virtue of the fact that the UR placed emphasis on such certification and included an allowance for it in the price control proposals that NIE rejected.

Transfer of activities to SONI

10.256 The EU decision on TSO certification which requires the transfer of transmission planning activities to SONI was made on 12 April 2013.

10.257 NIE submitted its Statement of Case to us in May 2013. The expenditure forecasts in its Statement of Case did not take account of the transfer of transmission planning to SONI.

10.258 In October 2013, NIE provided a note which set out the changes required to NIE's expenditure forecasts as a result of the proposed transfer of activities to SONI, which is anticipated to take effect on 1 April 2014. NIE forecast that the transfer would result in reductions in operating costs of around £2 million a year against its original plan (that plan included substantial increases in opex related to work to accommodate renewable generation; NIE referred to this as the renewable baseline). NIE also identified reductions to its pension costs.

10.259 This note was just over a page in length. It does not provide a basis on which we can make an assessment of the impact of the anticipated transfer on our cost assessment. Further, there remains uncertainty about the details of that transfer and it seems difficult to estimate the impact on NIE's costs. It is possible that NIE's costs reduce by more than suggested in the note referred to above.

10.260 The UR told us that it was not necessary for us to consider the impact of the anticipated transfer of some transmission network planning responsibilities to SONI and that the details of final roles and responsibilities would not be approved until after February 2014.

10.261 We propose that changes to NIE's price control are proposed by the UR as part of the licence modifications to implement the transfer of transmission planning to SONI. The UR may need to extend the scope of its consultation process on licence modifications to include a review of the impact on NIE's costs. We would expect the UR to take account of the way that we have made our cost assessment in deciding on an appropriate adjustment (eg our use of GB DNO benchmarking for indirect costs and an adjustment to scale up benchmarked costs to include an allowance NIE's 275 kV network).

11. RPEs and productivity

Introduction

11.1 In this section we make a forecast of how an efficient firm's costs would be expected to move compared with RPI since the base year of the revenue control (2009/10). This is so that we can apply any difference (either positive or negative) to NIE's cost allowances so that they better reflect the likely path of costs which an efficient firm would face. NIE's cost allowances are covered in Sections 7 to 10.

11.2 The section is structured as follows:

- *(a)* We explain why we are considering RPEs[1] together with productivity in our analysis.
- *(b)* We make a provisional forecast for the level of annual productivity growth which we expect from NIE in opex and capex.
- *(c)* We explain our approach to forecasting RPEs and make an RPEs forecast for the period.
- *(d)* We consider NIE's additional request relating to the EU Transformer Directive.
- *(e)* We conclude by showing the combined effect of our productivity and RPE forecasts.

Our approach to RPEs and productivity

11.3 Over a charge control period an efficient firm will be subject to two different pressures on its cost base. These are changes in:

- *(a)* *productivity* (for example, increased output with constant inputs) which we will capture through an estimate of potential incremental efficiency improvements over the period; and

[1] Real price effects (RPEs) make a forecast of how a firm's costs will differ from inflation (in this case RPI) over a period.

(b) *input prices* (for example, labour and materials) which will be captured through a forecast of RPEs over the period.

11.4 We have therefore made an estimate for both productivity and RPEs and apply the combined effect to NIE's cost allowances (see Sections 7 to 10).

11.5 We begin by considering productivity.

Productivity

11.6 To make an estimate of productivity we considered the following:

(a) other recent regulatory decisions on productivity;

(b) the EU KLEMS growth and productivity accounts; and

(c) the recently submitted RIIO-ED1 business plans of the GB DNOs.

11.7 We did not consider extrapolating from NIE's past productivity gains as we preferred an assessment of productivity which was independent of the company (see Section 8 on the benefits of benchmarking).

Other regulatory decisions on productivity

11.8 We considered some recent productivity estimates made by other regulators. These are shown in Table 11.1.

TABLE 11.1 **Opex and capex productivity assumptions in other price control reviews**

	%
Opex productivity	
UR—Water and sewerage	0.9
PPP Arbiter—underground infracos, central costs	0.7
PPP Arbiter—underground infracos, opex	0.9
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	1.0
ORR—Network Rail, opex	0.2
ORR—Network Rail, maint	0.7
Capex productivity	
PPP Arbiter—underground infracos	1.2
Ofgem—GB DNOs	1.0
Ofgem—Transmission & Gas Distribution	0.7
ORR—Network Rail	0.7

Source: UR, CC analysis.

Notes:
1. UR's PC13 Water and Sewerage determination relates to 2012 .
2. PPP Arbiter's decision for underground infrastructure companies (infracos) relates to 2010 Ofgem's decision for DNOs relates to 2009.
3. Ofgem's decision for Transmission and Gas Distribution relates to 2012.
4. ORR's decision for Network Rail relates to 2008.

11.9 These decisions indicated a range of productivity assumptions of between 0.7 and 1.2 per cent for capex and between 0.5[2] and 1.0 per cent for opex. We decided that Ofgem's decisions in respect of the GB DNOs and also in respect of Transmission & Gas Distribution were most relevant because they relate to businesses which most closely resemble NIE:

(a) In 2009, Ofgem set a 1.0 per cent productivity assumption for both capex and opex for the GB DNOs. Ofgem said that this was consistent on its own productivity analysis and the assumptions made by First Economics in a report for the GB DNOs. It said that it had received limited challenge from the GB DNOs on its productivity assumption.[3]

(b) In 2012, Ofgem used a 1.0 per cent assumption in respect of opex and a 0.7 per cent assumption in respect of capex for Transmission and Gas Distribution. Its assumptions drew on the EU KLEMS data set (which we discuss below in paragraphs 11.10 to 11.14). Its opex assumption was based on UK average industry partial factor productivity measures for 1970 to 2007 (ie labour, and labour and

[2] Representing the simple average of the ORR opex and maintenance decisions from 2008.
[3] Ofgem DPCR5 Allowed Revenue - Cost Assessment, 7 December 2009, p81.

intermediate inputs); its capex assumption was at the top end of construction total factor productivity[4] (TFP), which was its preferred industry, but below TFP for other industries. Ofgem noted that its opex efficiency assumption of 1.0 per cent was in line with network company assumptions.[5]

EU KLEMS data

11.10 There is a significant amount of relevant work which has been completed by other regulators and consultants using the EU KLEMS[6] data set. This data provides growth and productivity accounts for 36 sectors, subsectors and subsubsectors of the UK economy for the period between 1970 and 2007.

11.11 We considered that EU KLEMS was a useful source of information covering a long period, albeit that it has the disadvantage of ending in 2007 and being backward looking.

11.12 Table 11.2 shows the aggregate average annual productivity growth rates (ie for the UK economy as a whole) based on different measures of productivity.

TABLE 11.2 **Average annual TFP growth rates for different sectors using EU KLEMS, 1970 to 2007**

per cent

Sector/group	*TFP (VA)*	*Labour & intermediate input productivity (VA) at constant capital*	*TFP (GO)*	*Labour & intermediate input productivity (GO) at constant capital*	*Labour & intermediate input productivity (GO)*
Unweighted average all industries	1.3	1.5	0.5	0.5	0.8

Source: EU KLEMS/Ofgem RIIO—T1/GD1: Real Price Effects and ongoing efficiency appendix, p15, 17 December 2012.

Notes:
1. The averages used by Ofgem exclude the following industries: real estate, public administration, education, health and social services.
2. VA = value added measure.
3. GO = gross output measure.

[4] TFP is a measure of productivity which encompasses all elements of production.
[5] Ofgem RIIO-T1/GD1. Real Price Effects and ongoing efficiency appendix, 17 December 2012, Chapter 3.
[6] EU KLEMS: www.euklems.net/.

11.13 For opex we considered that measures of labour productivity would be a more appropriate benchmark than TFP. This is because NIE's opex costs are close to 80 per cent labour and labour productivity should therefore be the most significant driver of opex productivity. This compares to a labour content of around 50 per cent for NIE's capex. This would support a marginally higher opex productivity assumption (as compared to capex) when using the EU KLEMS data.

11.14 Overall we considered that the aggregate EU KLEMS data could support a range of estimates of productivity of between 0.5 and 1.5 per cent. A summary of the EU KLEMS data and reports which we considered is contained in Appendix 11.1.

Evidence from the business plans submitted by the GB DNOs

11.15 The GB DNOs have all recently submitted business plans to Ofgem as part of its RIIO-ED1 (2015–23) price control. We considered that the incremental efficiency improvement forecast in these plans was a highly relevant data set. This is because, rather than relating to the past, it reflects a forward-looking view of potential incremental improvements in efficiency from a set of highly comparable companies.

11.16 In addition, we note that in its guidance Ofgem said that efficiency assumptions should represent the level which even the most efficient business would be able to achieve.[7] There should therefore be no 'catch-up' embedded in these estimates of efficiency.

11.17 Most of the GB DNO business plans contain an assumption that overall cost efficiency can be improved at 1 per cent a year.[8] These include WPD, Electricity North West, SSE and Scottish Power. UK Power Networks expects to absorb the

[7] www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview , paragraph 4.40.
[8] In these examples, unless otherwise stated, costs are totex (ie opex plus capex).

impact of any RPEs fully through efficiencies. Northern Powergrid’s plan contains an assumption of 1.0 per cent efficiency in opex and 0.7 per cent in capex.

Conclusion on productivity

11.18 We decided that the most relevant data points in setting our productivity assumption were the forward-looking business plans of the GB DNOs and we therefore placed significant weight on this data. This is because we believe that there is a large overlap between NIE’s business activities and that of the GB DNOs.

11.19 Based on the business plans of the GB DNOs, we saw no reason why NIE should not be challenged to make a similar level of incremental efficiency improvement. This indicated a level of capex and opex productivity of 1 per cent a year. We note that this is within the range of productivity indicated in our assessment of the EU KLEMS data; it is also within the range of values indicated by recent regulatory decisions and close to the 2009 and 2012 Ofgem decisions on productivity (which we considered to be the most relevant of recent regulatory decisions on productivity).

11.20 We therefore provisionally determined that a productivity assumption of 1 per cent a year should be applied to NIE’s costs (ie to each of opex and capex).

RPEs

11.21 In this section, we make a forecast for RPEs. That is, we make a forecast for how we expect NIE’s cost inflation to differ from RPI. We begin by explaining some key aspects of our approach. We then outline our forecast.

Our approach to RPEs

11.22 NIE's overall costs were split according to the categories which Ofgem had used in DPCR5.[9] These categories of cost were:

(a) *labour,* which was split between 'specialist' and 'general' elements;

(b) *general materials,* which are construction materials excluding metals;

(c) *specialised materials,* which includes cables, cable containment, transformers and switchgear;

(d) *plant and equipment,* which is equipment that is not an integral part of the networks but is used on site; for example: welding and lifting equipment; mobile generators; testing equipment; transport equipment; and plant costs such as mobile offices; and

(e) *other,* which is items that could not be classified as one of *(a)* to *(d)* above.

11.23 We found that these broad cost categories were a reasonable starting point for our analysis. We therefore decided that we would forecast RPEs for each of these broad categories of cost and then use these forecasts to model an overall level of RPE for each of capex and opex. To do this we took the following approach:

(a) we made a forecast of nominal price inflation for each input category;

(b) we calculated an RPE for each input category by comparing our nominal price inflation forecast to RPI; and then

(c) we assigned a weighting to each input category for each of capex and opex in order to calculate an overall capex RPE and opex RPE for each year of our forecast.

11.24 Our forecast can be split into two parts: the 'historic forecast', which applies to the period from 2009/10 (the base year) to 2012/13 and for which actual historic data is

[9] Ofgem commissioned CEPA to produce price inflation forecasts for that charge control and we have therefore assumed that the definitions contained in CEPA's report, *Update of Input Price Inflation Forecasts for DPCR5* (2009), accurately reflect the category definitions.

available; and the ‘forward-looking forecast’, which applies to the period from 2012/13 until September 2017.

11.25 For completeness, each of the years in our forecast runs from April to March: our first forecast year is therefore April 2010 to March 2011 and our last full forecast year is April 2016 to March 2017. As our revenue control ends to September 2017 we have in addition made a forecast for the six-month period April 2017 to September 2017.

11.26 We now explain in further detail some of the key aspects of our approach, including those areas where our forecasting method differed from that proposed by the parties.

Use of the OBR forecast

11.27 We considered that the OBR’s economic and fiscal outlook represented a coherent and independent forecast which covered the entire period of our forecast. We did not identify a better alternative to this forecast. We therefore decided that, wherever possible, we would use this as the basis for our RPE forecast. The OBR forecasts both RPI and wages. It also forecasts the level of producer output price inflation.

11.28 The OBR forecasts are updated in March and December of each year. We used the March 2013 forecasts as the latest available forecast.

Distinction between specialist and generalist labour

11.29 When constructing its proposed RPEs, the UR and its consultants First Economics (FE) split labour into ‘specialist’ and ‘general’ categories; it used a premium of 1.25 per cent above general wage inflation to forecast specialist labour inflation. Separately, NIE defined its specialist labour as composing all managerial, professional and engineering staff as well as the majority of its industrial and administrative staff.

11.30 NIE made several submissions with regard to its specialist labour. However, we did not find that the distinction between specialist and generalist labour was helpful. This was because these are very broad categories involving employees with different types of skills who could be subject to quite different labour supply and demand conditions.

11.31 We did not believe that by using these categories we would make a forecast of NIE's labour inflation that was more precise and we judged that in many instances the distinction between the two categories would be arbitrary. We therefore did not split NIE's labour between 'specialist' and 'general' categories.

Forecasting input categories for which there is no OBR forecast

11.32 The OBR does not make a forecast for several input categories. It does, however, forecast overall producer output prices. To forecast these input categories we therefore identified a number of price inflation indices which we considered were highly relevant to each particular input category.

11.33 We then applied the actual rate of inflation from these indices for the period 2009/10 to 2012/13. For the forecast period 2012/13 to September 2017 we applied the long-term average level of inflation indicated by these indices. In each case, we have used an unweighted average of our selected category price inflation indices.

11.34 Table 11.3 shows the indices which we have used for each input cost category.

TABLE 11.3 **CC choice of relevant indices for each input category**

Category	*Indices chosen*	*CC comment*
General materials	BIS: Resource Cost Index of Infrastructure Materials (FOCOS) BIS: Resource Cost Index of Building (non-housing) Materials (NOCOS)	Captures inflation in a wide range of purchased building materials
Specialist materials	ONS PPI: Electric motors, generators and transformers; electricity distribution and control equipment (JV6R) ONS PPI: Electricity distribution and control apparatus (JV72) ONS PPI: Other electronic and electric wires and cables (K32F) ONS PPI: Cold Drawn Wire (JV2C)	These PPI indices capture a number of specialist inputs purchased by electricity network operators
Plant & equipment	ONS PPI: Machinery and equipment output BCIS: Plant and Road Vehicles (90/2)	Covers a broad range of general and special purpose machinery which should be a relevant to electricity network operators
Other	RPI	We have assumed that inputs in this category inflate with RPI

Source: CC analysis/ONS.

Note: We made use of Ofgem's work on RPEs in DPCR5 and Scottish Power Energy Network's 2015–23 business plan submission (Annex 3.3, Tables 2.1–2.3) in selecting these indices: www.spenergynetworks.com/serving_our_customers/pdf/201306_SPEN_AnnexVol1_3Contents.pdf.

11.35 To calculate the longer-term average level of input price inflation which should apply to the forecast period 2012/13 to September 2017 we used data from these indices covering the period 1996 to 2012. We considered that this was an appropriate period because:

(a) in our judgement it is a sufficiently long period which covers both expansion and contraction in the UK and global economies; and

(b) producer output prices as a whole increased by on average 1.9 per cent a year over this period. This is close to the average level of producer output price inflation forecast by the OBR over the forecast period (2.1 per cent). The OBR is therefore forecasting a level of producer output price inflation during our forecast period which is broadly representative of the level of producer price inflation seen in our sample period.

11.36 We chose not to 'fade up' or 'fade down' the level of input price inflation from the level seen in 2012/13 towards our calculated average for the 1996 to 2012 period. To do so would be to place undue significance on the rate of input inflation which had occurred in 2012/13. We therefore decided to apply our long-term average level of category input price inflation to each year of our forecast period.

Input weightings

11.37 The UR proposed applying Ofgem's weightings from DPCR5 to NIE. These use a notional company structure, which was derived as the average of the weights contained in the DNOs' business plans for DPCR5.[10] Ofgem will continue to use this approach in RIIO-ED1. The DPCR5 weightings are shown in Table 11.4.

TABLE 11.4 **Input weights assumed by Ofgem in DPCR5**

per cent

	Capex			*Opex*		
	Load-related	*Non-load-related*	*Non-operational capex*	*Network operating costs*	*Closely associated indirect costs*	*Business support costs*
General labour	30	32	31	59	51	45
Specialized labour	30	32	16	30	25	22
General materials	9	10	53	8	11	4
Specialized materials	14	15	0	0	0	0
Plant & equipment	9	10	0	0	0	0
Other	8	1	0	3	13	29
Total	100	100	100	100	100	100

Source: Ofgem, Electricity Distribution Price Control Review Final Proposals, Allowed revenue and cost assessment, 7 December 2009, Table 5.2.

11.38 This approach has the advantage of being simple and not encouraging any particular type of company structure. NIE is also keen to report along the same lines and be benchmarked against the GB DNOs for efficiency.

11.39 However, we decided that it would be more appropriate to use NIE's own input weightings. This is because these weightings reflect the specific characteristics of NIE's own business. We considered that the risk that NIE (or any company) would change its input weightings in order to try to improve future RPE allocations was very low.

[10] Ofgem, Electricity Distribution Price Control Review Final Proposals, Allowed revenue and cost assessment, 7 December 2009, paragraph 5.8.

11.40 NIE's input weightings are outlined in Table 11.5. We have combined general and specialist labour to reflect our view that this distinction is not helpful (see paragraphs 11.29 to 11.31 above).

TABLE 11.5 **NIE's proposed RPE weightings**

	Capex weight	*Opex weight*
Labour	52.8	77.3
Materials—general	11.6	7.7
Materials—specialist	18.6	0
Plant & equipment	5.9	0
Other	11.0	15.0
Total	100.0	100.0

Source: NIE Statement of Case, 10 May 2013, p218.

Note: Numbers may not sum due to rounding.

Our RPE forecast

11.41 In this section, we explain our historic and forward-looking RPE forecast for each category of input:

(a) labour; and

(b) general materials, specialist materials and plant & equipment

Labour RPEs

11.42 NIE submitted that for the historic forecast its wage settlements should be used.[11] These were significantly in excess of the levels of labour inflation seen in the UK economy as a whole. We considered that NIE's proposed approach had the advantage of accurately reflecting the actual agreements which it had reached with its workforce during the period in question. However, we believed that there were two disadvantages to its proposed approach:

(a) NIE's settlements represent a narrow measure of its labour costs as they do not properly capture the price of brought-in labour, for example subcontractors.

(b) using NIE's settlements would amount to a straight pass-through of actual wage settlements to consumers. These settlements may or may not have been set at

[11] NIE Statement of Case, 10 May 2013, Ch8, paragraph 3.4.

an efficient level. Taking a pass-through approach would introduce the risk that a company could be rewarded for inefficient wage settlements.

11.43 We were particularly concerned about a straight pass-through of wage settlements to consumers and we therefore provisionally decided that we could not use NIE's own wage settlement data as a basis for setting the historic labour forecast.

11.44 We therefore considered what alternative measures of wage inflation were available to us. Since the historic labour inflation forecast was making a forecast for a period where out-turn data is available, we found that there were several potentially relevant data points.

11.45 First, we considered average weekly earnings. Average weekly earnings data is a good measure of general wage inflation in the UK economy. This measure of labour inflation was 2.8 per cent in 2010/11, 0.9 per cent in 2011/12 and 2.1 per cent in 2012/13.[12]

11.46 Second, we considered the UR's submission that we could use JIB[13] hourly rates of pay. These might be particularly pertinent for some of the brought-in labour elements of NIE's costs (ie that element which is subcontracted). The relevant JIB hourly rates were held constant between January 2010 and January 2013 in response to the recession and the drop-off in the volume of work in the contractor market. That is, there was a rate of nominal labour inflation of zero.

11.47 Third, we considered whether the wage settlements of the GB electricity network companies over this period might be a useful alternative benchmark. This data suggested a level of labour inflation over this period slightly in excess of the UK

[12] We have adjusted the AWE data to reflect a constant working week (ie no change in hours worked over the period).
[13] Joint Industry Board for Electrical Contracting Industry.

labour market as a whole. The public data on trade union settlements is shown in Table 11.6.

TABLE 11.6 **Union nominal pay settlements at GB electricity network companies, 2010 to 2012**

per cent

	2010	*2011*	*2012*
Range	2.0–4.9	2.5–5.2	2.5–4.5
Average	3.0	3.6	3.7

Source: NIE Statement of Case, Annex 8A.1, p442.

Note: The data comprises only the settlements of Unite and Prospect unions at the following companies: [✂].

11.48 We found that this data offered two advantages: it is a larger sample which is independent of NIE, and the businesses concerned have a large overlap in the type of labour they employ (albeit on a different island). At the same time, we recognized that the data was still a narrow measure of NIE's labour costs.

11.49 Fourth, we considered the ONS ASHE survey.[14] This data provides information on various categories of labour. It allowed us to see the rate of labour inflation in certain categories of labour which might be more relevant to NIE. Table 11.7 shows this data.

[14] Annual Survey of Hours and Earnings.

TABLE 11.7 **ONS ASHE data on various categories of labour in the UK and Northern Ireland**

Category (code)	2010 UK	2010 Northern Ireland	2012 UK	2012 Northern Ireland
Professional occupations (2)	1.5	2.2	0.2	2.0
Engineering professionals (212)	1.5		2.1	
Electrical engineers (2123)	3.2		3.3	
Electronics engineers (2124)	3.0		2.1	
Electrical/electronics technicians (3112)	3.0		0.8	
Engineering technicians (3113)	2.9		1.2	
Building and civil engineering technicians (3114)	–0.3		–4.8	
Skilled metal and electrical trades (52)	3.1	–0.6	0.6	–1.9
Electrical and electronic trades (5249)	3.4		0.5	1.5
Electricians, electrical fitters (5241)	3.3		–1.6	
Skilled construction and building (53)	2.8	1.4	–0.2	2.9

Source: ONS ASHE data/CC analysis.

Notes:
1. Where cells are blank data is not available.
2. In 2011 the categories were changed and therefore % change for 2011 is not available.
3. OBR AWE was 1.6 per cent for 2010 and 2.0 per cent for 2012.

11.50 NIE said that the categories Electrical Engineers (2123) and Electrical/electronic technicians (3112) were most relevant to an assessment of its workforce. We found that this data suggested that certain relevant electrical engineering professional and trades saw labour inflation over this period that was slightly above that seen in the UK economy as a whole.

11.51 Of the four data sources that we considered, we placed most weight on the wage settlements of the GB electricity network companies. This is because there is a large overlap with NIE in the type of labour these companies employ. We also relied, although to a lesser extent, on the ONS ASHE survey. This is because this data allowed us to consider categories of labour particularly relevant to NIE.

11.52 In our view, the wage settlements of the GB electricity network companies indicate a rate of nominal wage inflation in the range of 3.0 to 3.7 per cent over the period 2010 to 2012; and the ONS ASHE data indicates a rate of nominal wage inflation slightly below this level. We therefore provisionally judged that a rate of nominal wage inflation of around 3.25 per cent for the forecast period 2009/10 to 2012/13 was appropriate.

11.53 For the forward-looking wage inflation forecast (2012/13 to September 2017) we used the OBR forecast for average weekly earnings. This is consistent with our decision to use OBR forecast data wherever possible. We provisionally decided that it was appropriate to make an adjustment to this data to reflect constant working hours so that our forecast reflected increases in hourly wages rather than an hourly wages plus changes in hours worked. For the forecast period this resulted in a slight increase in the forecast level of pay inflation as the OBR forecasts a slight reduction in hours worked over the period.

11.54 Table 11.8 summarizes our labour RPEs for the period.

TABLE 11.8 **Labour RPE, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
Labour RPE	–1.6	–1.5	0.2	0.2	1.2	1.1	0.5	0.1

Source: OBR/CC analysis.

Note: Figures may not sum due to rounding.

11.55 Further details of the discreet nominal forecast which was used to derive the RPEs in Table 11.8 above are in Appendix 11.1.

General materials, specialist materials and plant & equipment RPEs

11.56 Table 11.9 shows our general materials, specialist materials and plant & equipment RPEs for the RP5 period. These have been derived using the method described above in paragraphs 11.32 to 11.36.

TABLE 11.9 **General materials, specialist materials and plant & equipment RPEs, 2009/10 to September 2017**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
General materials RPE	3.5	1.8	–2.0	1.1	1.2	0.8	0.4	0.1
Specialist materials RPE	5.9	–0.1	–4.9	0.0	0.2	–0.2	–0.6	–0.4
Plant & equipment RPE	–3.3	–2.1	–1.8	–0.7	–0.6	–0.9	–1.3	–0.6

Source: CC analysis.

11.57 Further details of the discreet nominal forecast which was used to derive the RPEs in Table 11.9 are in Appendix 11.1.

Summary of our RPE forecast

11.58 Combining the RPEs for each of the input categories with our capex and opex input weightings (see paragraphs 11.37 to 11.40) results in the RPEs shown in Table 11.10. Table 11.10 also shows the RPE forecast submitted by NIE for RP5 and the UR's final determination in this area.

TABLE 11.10 **CC capex and opex RPEs compared with NIE and the UR's final determination**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE	0.5	–0.7	–1.2	0.2	0.8	0.6	0.1	0.0
CC opex RPE	–1.0	–1.0	0.0	0.2	1.0	0.9	0.5	0.1
NIE's proposed RPEs								
Capex RPE	1.5	1.9	0.6	0.4	1.2	1.3	1.1	
Opex RPE	0.5	1.1	1.3	0.3	1.0	1.3	1.1	
UR's final determination								
Capex RPE	+£0.6 million as a fixed allowance for RP5							
Opex RPE	–£3.3 million as a fixed allowance for RP5							

Source: CC analysis; NIE Statement of Case, Chapter 8, Table 8.3, p218; and UR Final Determination.

11.59 It can be seen from Table 11.10 that our forecast of capex and opex RPEs is lower than that submitted by NIE. It is closer to that made by the UR. The two most significant reasons for the difference between our forecast and NIE's submission are:

(a) We have not used NIE's actual wage settlements for the historic labour forecast, as we provisionally decided that we did not want to use a measure of wage

inflation which would amount to a straight pass-through of these costs (see paragraphs 11.42 to 11.52).

(b) We have not used a distinction between ‘specialist’ and ‘generalist’ labour (see paragraphs 11.29 to 11.31).

NIE additional request arising from the EU Transformer Directive

11.60 We considered NIE’s request for an additional £5.0 million during RP5 due to this directive, which requires that transformers up to 36 kV should be designed and constructed to meet new standards.

11.61 We decided that first, this is not an item which we would expect to be considered specifically in an RPE forecast (which by its nature forecasts more general changes in broad input categories). Second, our RPE forecast makes a broad allowance for the estimated level of input price inflation which NIE will experience in RP5 and that it would not be in customers’ interests to make additional uplifts to this allowance for specific items.

11.62 This is because the overall level of input price inflation which NIE actually experiences will be the result of the level of inflation experienced in many different input items: some of these inputs will experience positive levels of inflation relative to RPI, others negative; if we were to include additional allowances for individual items where above-average levels of inflation might be expected, we would introduce an unfair upward bias into our RPE forecasts.

Our provisional determination

11.63 We believe that the effects of both productivity and RPEs will affect NIE’s cost base in each year following the base year forecast. We therefore provisionally determined that both forecasts should be applied from the base year until the end of RP5. That is, our productivity and RPEs forecasts should apply from 2009/10 until September 2017 for each of opex and capex.

11.64 Table 11.11 summarizes the combined effect of our provisional RPE and productivity forecasts for the period from 2009/10 until September 2017.

TABLE 11.11 **Combined effect of CC productivity and RPEs for RP5**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE plus productivity	–0.5	–1.7	–2.1	–0.8	–0.2	–0.4	–0.8	–0.5
CC opex RPE plus productivity	–2.0	–2.0	–1.0	–0.8	0.0	–0.1	–0.5	–0.4

Source: CC analysis.

is, our productivity and RPEs forecasts should apply from 2009/10 until September 2017 for each of opex and capex.

11.64 Table 11.11 summarizes the combined effect of our provisional RPE and productivity forecasts for the period from 2009/10 until September 2017.

TABLE 11.11 **Combined effect of CC productivity and RPEs for RP5**

	2010/11	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*6m to Sept 2017*
CC capex RPE plus productivity	–0.5	–1.7	–2.1	–0.8	–0.2	–0.4	–0.8	–0.5
CC opex RPE plus productivity	–2.0	–2.0	–1.0	–0.8	0.0	–0.1	–0.5	–0.4

Source: CC analysis.

12. Pensions

Introduction

12.1 In this section, we outline our provisional decisions in respect of pensions. We deal mainly with the defined benefit (DB) pension scheme of NIE's regulated business, which is currently in deficit. The section is structured as follows:

(a) We explain some of the background to the NIE Pension Scheme.

(b) We outline our approach to pensions and list the questions which we consider it is necessary to answer in order to make a provisional determination in respect of pensions.

(c) We explain our provisional decisions and reasoning in respect of each of those questions which we have identified.

12.2 The extensive background, arguments made by the parties and discussion of relevant pensions precedents can be found in Appendix 12.1.

Background to the NIE Pension Scheme

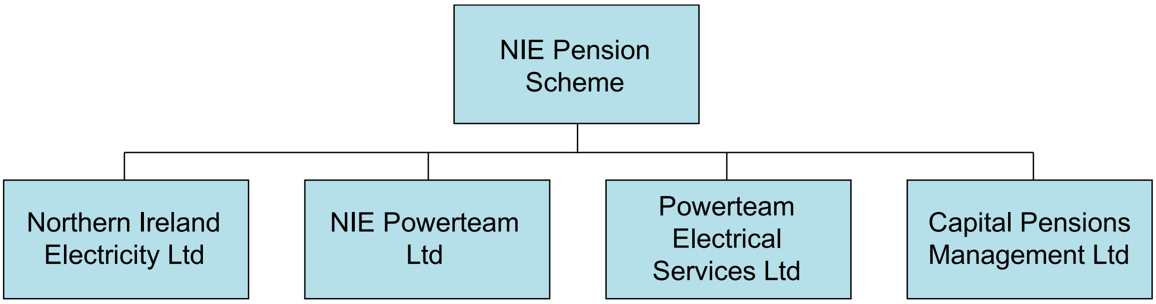
12.3 NIE was privatized in 1993 and inherited sponsorship of the NIE Pension Scheme (the scheme), a DB pension scheme. Protected persons[1] represent 97 per cent of the scheme's members.[2]

12.4 The participating employers in the scheme are shown in Figure 12.1.

[1] Protected persons are protected by statute and their pension benefits cannot be reduced without their consent. This applies to both past and future service.
[2] NIE Statement of Case, Chapter 10, paragraph 2.2.

FIGURE 12.1

Membership of the NIE Pension Scheme



Source: NIE RP5 Final Determination, p66.

12.5 Figure 12.1 shows that the scheme covers three other legal entities in addition to NIE Ltd. These are:

(a) *NIE Powerteam Ltd*, which employs a large number of staff and carries out work on the NIE network which is within the scope of NIE T&D's regulated activities;[3]

(b) *Powerteam Electrical Services Ltd,* which provides services that fall outside the scope of NIE's regulated activities; and

(c) *Capital Pensions Management Ltd,* which employs a small number of staff responsible for managing the pension scheme.[4]

12.6 Prior to March 1998 all new employees working for NIE were given membership of the DB scheme (known as 'Focus'). At this time NIE decided to close the scheme to new joiners and opened a defined contribution (DC) scheme (known as 'Options') for employees who joined after March 1998.[5,6] Protected Persons cannot be transferred from the DB 'Focus' scheme to the DC 'Options' scheme.[7]

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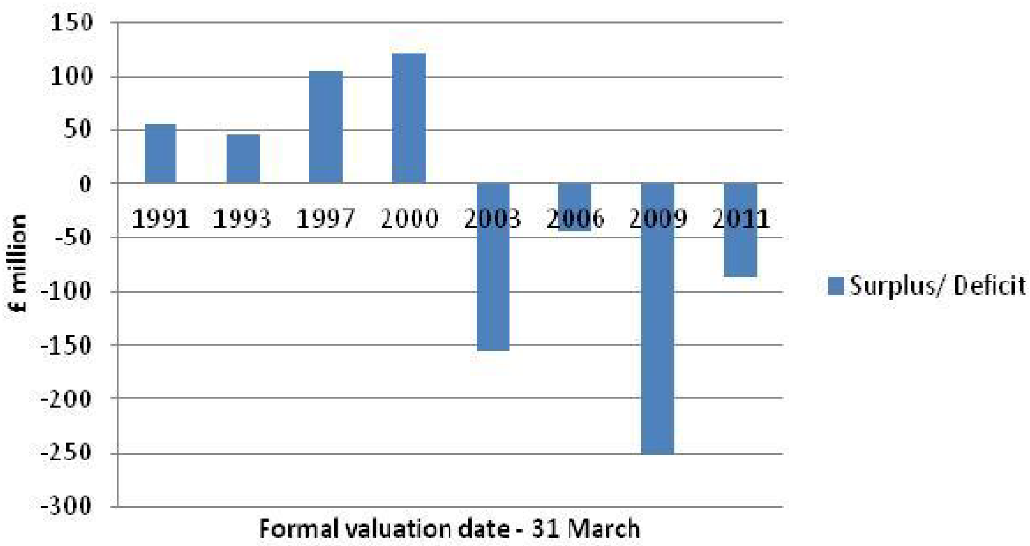
[3] The relevant costs for NIE Powerteam appear to have been consolidated into the costs of transmission and distribution activities in NIE's regulatory accounts although this is not explicitly stated.
[4] UR paper on Pensions, UR-5, paragraph 4.
[5] ibid, paragraph 3.
[6] NIE Statement of Case, Chapter 10, paragraph 2.5.
[7] ibid, Chapter 10, paragraph 2.5.

12.7 Figure 12.2 shows the development of the scheme's surplus/deficit at its formal valuation dates since 1991.

FIGURE 12.2

NIE Pension Scheme surplus/deficit at formal valuation dates



Source: UR paper on Pensions, UR-5, Chart 2, p2.

12.8 It can be seen that there has been considerable variation in the funding position of the scheme and a notable deterioration since the early 2000s. This has been a common feature of DB pension schemes in the UK.

12.9 NIE said that the performance of the scheme since the last formal triennial valuation (in March 2011) had been adverse and that the deficit at 30 September 2011 was approximately £150 million. The annual actuarial report as at 31 March 2012 showed a deficit of £156.4 million.[8] NIE agreed an increase in contribution payments to address the deficit following the 2009 valuation and these payments were retained

[8] ibid, Chapter 10, paragraph 2.7.

following the 2011 annual valuation.[9] The latest funding update showed a deficit of £135.5 million as at 16 May 2013.[10]

12.10 In the 1990s the scheme was in surplus. This surplus was drawn on to fund benefit improvements for members and contribution cost reductions for NIE. The latter included the cost of funding both benefits as well as early retirement schemes run by NIE.[11] NIE suggested that the scheme surplus was broadly distributed 2:1 between the company and employees.[12]

12.11 NIE's shareholders, as part of an agreement with the trustees struck during the 2006 acquisition by Arcapita, agreed to clear the deficit as at 31 March 2006 by the payment of special contributions.[13]

Our approach to pensions

12.12 In order to reach a determination on pensions, we considered that it was necessary to answer the following questions:

(a) Which of the NIE pension schemes (as shown above in Figure 12.1) should we include in our determination?

(b) How should we treat the deficits of any schemes which we have included in our determination (before consideration of any special items)?

(c) If we allow some deficit repair payments to be passed through to consumers, over what period should this be?

(d) If the deficit recovery period we choose is not equal to the repayment schedule which NIE has agreed with its pension trustees, should NIE be compensated for the resulting financing costs?

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[9] ibid, Chapter 10, paragraphs 2.7, 2.14.
[10] NIE Supplementary Submission, Annex 8, paragraph 2.5.
[11] ibid, Chapter 10, paragraph 2.9.
[12] ibid, Chapter 10, paragraph 2.10.
[13] ibid, Chapter 10, paragraph 2.12.

(e) Which pension scheme valuation should be used to calculate any deficit repair payments?

(f) NIE has made deficit repair payments in excess of its allowances in RP4 (which it refers to as ‘stranded costs’). Should NIE be refunded these stranded costs (and if so, on what basis)?

(g) The NIE pension scheme incurred liabilities relating to unfunded early retirement schemes run by NIE between 1997 and 2003; this is known as the ERDC liability. In RP4 NIE funded 30 per cent of this liability and consumers funded 70 per cent. Is this an appropriate basis on which to split this liability between NIE shareholders and consumers?

(h) NIE said that previous special contributions to the pension scheme made by its shareholders should be offset against any ERDC liability. Do we agree with NIE’s proposed treatment?

(i) NIE also incurs ongoing pension costs which are not linked to deficit repair. These are the costs of NIE’s employer contributions to its DB and DC schemes. How should ongoing pension costs be treated in RP5?

12.13 In the following subsections, we set out and explain our provisional decisions in respect of each question listed above.

Schemes to be included in our provisional determination

12.14 We considered which of the NIE pension schemes (as shown in Figure 12.1 above) should be included in our provisional determination. Funding relevant costs is in the public interest. Otherwise there would be a risk that services would not be provided. Relevant costs should only include items relevant to providing the services consumers receive.

12.15 We provisionally decided that only the pension schemes which provide services exclusively to the regulated business of NIE were relevant costs. These are NIE Ltd and NIE Powerteam Ltd (which provides services exclusively to NIE). Capital Pensions Ltd and Powerteam Electrical Services Ltd, which do not provide services exclusively to NIE, should therefore be excluded.

12.16 We note that this is in line with the UR's final determination for RP5, which resulted in a regulatory fraction of 99.26 per cent.

Treatment of pension deficits included in our provisional determination

12.17 We considered how scheme deficits included in our determination should be treated. We first considered NIE's ability to influence the level of deficits which had accumulated in the relevant schemes. We found that, because the pension scheme had been closed to new members since 1998 and 97 per cent of the members were 'Protected persons',[14] NIE had a fairly limited ability to influence the level of the pension scheme deficit which had accumulated.

12.18 We considered that it was also in the public interest to give NIE a strong incentive to try to manage its pension liabilities. This is because the current deficit is large and has been volatile in recent years: any actions which NIE can take to minimize its liabilities will ultimately be passed through to consumers through lower prices.

12.19 In this regard, we noted that only about 42 per cent of current NIE employees are protected persons. On a forward-looking basis, NIE therefore has a much better ability to manage its pension costs compared to the situation where almost all its current employees were protected persons. In addition, we expect that over time the

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[14] Protected persons legislation affects some former nationalized industries. Protected persons are protected by statute and their pension benefits cannot be reduced without their consent. Benefits must continue to be at least as good as they were in the public sector at the time the business was privatized. This applies to both past and future service.

percentage of current employees who are protected persons will continue to fall as new employees join the defined contribution scheme and older employees (who are in the DB scheme) retire. On this basis, we found that there was merit in taking a different approach to addressing the historic deficit and any new incremental deficit which may arise from additional pensionable benefits awarded to current employees.

12.20 This is the approach which has been taken by Ofgem in GB. For the GB DNOs, Ofgem distinguishes between the historic deficit and an incremental deficit. The historic deficit represents the difference between assets and liabilities attributable to pensionable service up until a defined cut-off date. The incremental deficit represents the difference between assets and liabilities for any pensionable service after this date. We note that Ofgem has spent considerable time refining and agreeing its methodology to calculate each deficit and that these are now included within its Pensions RIGS.[15]

12.21 We provisionally decided that NIE should also follow this approach, using the Ofgem Pension RIGS, with a cut-off date for the historic deficit at 31 March 2012. We then considered what proportion of each of the historic and incremental deficits should be attributable to each of NIE and consumers.

12.22 Based on the fact that NIE currently has a fairly limited ability to influence the historic scheme deficit, we decided that in principle (and before considering any special items) 100 per cent of the historic deficit repair costs should be passed through to consumers.

12.23 We provisionally decided that any incremental deficit should be funded 100 per cent by shareholders. This is because NIE has a much greater ability to influence its

[15] www.ofgem.gov.uk/ofgem-publications/42762/pdam-decision-letter-final-12apr2013.pdf.

forward-looking pension costs, as only 42 per cent of current employees are protected persons. Shareholders funding 100 per cent of any incremental deficit should provide NIE with a strong incentive to manage these liabilities, which we believe is in the public interest. We expect that, in conjunction with ongoing service costs, these costs will be subject to benchmarking with the GB DNOs in future price controls.

12.24 Our proposal would harmonize the treatment of pensions between NIE and the GB DNOs, which are its closest comparators. We believe that this will provide an additional benefit in future revenue controls by increasing the comparability and benchmarking of pension costs between NIE and the GB DNOs.

Deficit repair period

12.25 With the benefit of hindsight, deficit repair payments represent the recovery of historically understated labour costs. They are an intergenerational transfer since the set of consumers who will pay additional charges in order to repair the deficit are not the same as those who benefited from understated costs in the past. We therefore considered what an appropriate recovery period was for these additional costs.

12.26 We found that a relatively long period was appropriate, to—as far as is possible—minimize the impact on any one particular group of consumers. We noted that NIE had agreed with its trustees a 13-year recovery plan which will conclude in March 2022.[16] We also noted that there was some regulatory precedent (for example, Ofgem, CC Bristol Water) for a 15-year recovery period. A 15-year deficit recovery period beginning in April 2012 would mean that the deficit repair plan would conclude in March 2027.

[16] NIE Statement of Case, Chapter 10, paragraph 6.4.

12.27 We saw some benefit in matching the deficit recovery period with the actual repayment schedule which NIE had agreed with its trustees. However, in this case it would imply a recovery period of around ten years. In our judgement, a longer period than this was appropriate as ten years implies a relatively heavy burden on current consumers. We therefore provisionally decided that the deficit recovery period should be set at 15 years. We note that this is the same deficit repair period as in the UR's final determination.

12.28 Since we have provisionally decided that 100 per cent of the incremental deficit is attributable to NIE (paragraph 12.23), there will be no deficit repair payments for the incremental deficit.

Financing timing differences

12.29 We provisionally decided that consumers should fund deficit repair payments relating to the historic deficit over a 15-year period. However, NIE has agreed a shorter repayment schedule with its trustees. It will therefore make cash deficit repair payments to the scheme that are different (ie larger and ending sooner) from the profile of deficit repair payments which we have provisionally decided. We found that because the scheme is managed by independent trustees, NIE was unlikely to be able to change the repayment period which it had agreed. We therefore considered whether NIE should be compensated for these timing differences.

12.30 We have provisionally decided that, in principle, 100 per cent of NIE's historic pension deficit (before any adjustments for any special items) should be passed through to consumers. We therefore believe that it would be inconsistent if NIE were not compensated for financing costs which have arisen due to timing differences relating to the repayment of this historic deficit. This is because if we did not compensate NIE for these timing differences it would amount to a pass-through of less than 100 per cent of the historic deficit. We decided that NIE's WACC was the most appropriate discount rate to use for this calculation since it represented its cost of financing.

Valuation date to be used in calculating deficit repair repayments

12.31 The relevant pension scheme deficit has been relatively volatile in recent years: the most recent formal actuarial valuation in March 2011 had shown a deficit of £87.6 million[17] the 2009 valuation had shown a deficit of £251 million[18] and the latest funding update showed a deficit of £135.5 million as at 16 May 2013.[19] The choice of scheme valuation date to calculate the historic deficit therefore has a significant impact on the level of deficit repair payments which consumers are asked to fund.

12.32 We preferred to use the formal triennial actuarial valuation since it represented the most complete pension scheme valuation. However, we also considered that it was appropriate to use a basis of valuation which closely reflected the deficit which was actually being repaired. We noted that the plan which NIE had agreed with its trustees aimed to eliminate the deficit of £175 million at March 2010.[20] This plan was then retained to address a deficit of approximately £150 million as at 30 September 2011.[21]

12.33 We therefore decided that the last formal triennial valuation (a deficit of £87.6 million) did not reflect the deficit which is actually being repaired, nor did it reflect the most recent informal valuations of the scheme on which the deficit repair plan was based. We therefore provisionally decided that the valuation at 31 March 2012 was the most appropriate source on which to base calculations of the repayment profile for the historic deficit.

[17] ibid, Chapter 10, paragraph 2.14.
[18] ibid, Chapter 10, paragraph 2.13.
[19] NIE Supplementary Submission, Annex 8, paragraph 2.5.
[20] NIE Statement of Case, Chapter 10, paragraph 2.13.
[21] ibid, Chapter 10, paragraph 2.7.

12.34 We recognized that the deficit has been volatile in the recent past and that the historic deficit will change (perhaps significantly) in the future. We therefore provisionally decided that historic deficit repair costs should be revisited at each formal triennial actuarial valuation and additionally if any changes were made to the repayment schedule currently agreed with the trustees.[22] This will enable the deficit repair payment profile to change relatively quickly (either upwards or downwards) to reflect the most up-to-date valuation of the historic deficit.

12.35 This means that historic pension deficit repair costs may need to be adjusted during RP5 (for example, if deficit repair payments relating to the historic deficit were reduced, or increased, following the next triennial valuation). We provisionally found that this adjustment mechanism would add some additional complexity to the revenue control. However, in our view this additional complexity is warranted and in consumers' interests, given the historic volatility of the deficit: if the historic deficit changes significantly during RP5, then this should be reflected as soon as possible in the deficit repayment profile being funded by consumers.

Stranded deficit repair costs

12.36 We considered NIE's claim that it should be refunded £24 million of stranded costs from RP4. These costs arose because NIE's actual payments to the pension scheme were greater than its allowances in RP4.

12.37 We reviewed the arguments made by both parties in this area. It was unclear to us whether or not the RP4 pensions allowance (which NIE significantly exceeded) passed the full risk of pension costs to NIE (as the UR claimed) or just the financing risk associated with these payments (as NIE claimed).

[22] For completeness, we refer only to future changes in the quantum of payments, not to changes in the repayment period.

12.38 We provisionally proposed not to continue the pensions rolling mechanism from RP4. We also provisionally decided that, in principle, 100 per cent of the relevant historic deficit (before special items and up to the cut-off date of 31 March 2012) should be passed through to consumers. The payments in excess of its allowances which NIE made in RP4 were in respect of the historic deficit, which we have decided in this case is something which should be funded by consumers.

12.39 The direct result of our decision to end the RP4 pension mechanism is that, unless some provision for these stranded costs is made, NIE will have funded a greater proportion of deficit reduction costs than we intended. We considered the balance of the public interest and concluded that it remained appropriate for consumers to fund these stranded deficit payments because they related to the historic deficit, which we have provisionally decided should be funded by consumers. We decided that a 15-year recovery period was appropriate for these costs.

Early retirement costs

12.40 ERDCs represent the liability from unfunded early retirement schemes run by NIE between April 1997 and March 2003. Employees taking up the early retirement schemes during this period were entitled to unreduced pension benefits with pension payments beginning immediately rather than at their specified retirement age. At the time NIE did not make additional contributions to the pension scheme relating to these early retirement schemes. The ERDC liability represents the amount which would have been paid into the scheme at the time had these additional benefits been fully funded (adjusted for the investment returns that these contributions would have made in the period since).

12.41 In RP4 these ERDC liabilities had been split 30:70 between shareholders and consumers. This effectively adopted Ofgem’s decision on ERDCs, which was made in

2004. This split apportions the ERDC liability between shareholders and consumers on the basis of the benefit which each received (in the form of lower costs) from early retirement schemes.

12.42 We considered whether it was appropriate that consumers should be asked to fund any of the costs of these early retirement schemes. In our view, this part of the deficit was exacerbated by discretionary management decisions and it would not be in the public interest for consumers to fund these costs entirely. However, we also recognized that the large early retirement programmes which created the ERDC liability did reduce costs and that there was therefore some benefit to consumers from this.

12.43 We therefore considered how appropriate the current apportionment of the ERDC liability was (30 per cent to shareholders; 70 per cent to consumers). Our interpretation of Ofgem's 2004 decision was that it was strongly influenced by providing the companies with additional protection against the volatility of their pension schemes, thereby reinforcing the low-risk characteristics of the distribution business.[23]

12.44 The 30:70 split used by Ofgem (and on which the UR based its RP4 split) assumes that the company would have retained the present value of the benefits of reduced costs for five years (ie before price control allowances are reset); and that consumers benefit from reduced costs from year 6 into perpetuity. We considered that this was far from an exact calculation and that it also makes a number of assumptions which seem unlikely to reflect reality. For example: the calculation assumes that the workers taking early retirement would have otherwise stayed at the company for many years despite not being required; it also assumes that none of the leavers worked in capital expenditure programmes.

[23] Ofgem Update Paper, September 2004, paragraphs 5.16–5.17.

12.45 We noted that variations of this methodology have been used to suggest different allocations between shareholders and consumers. For example:

(a) It has been argued that most of the employees taking early retirement would have retired anyway within ten years; the benefit to consumers would therefore accrue only from years 6 to 10. This line of reasoning has been used to suggest 'at least a 50:50 split' between consumers and shareholders.[24]

(b) It has been argued that early retirements in fact occurred over the course of a price control rather than all occurring at the start; the benefit to the company was therefore less than five years. This line of reasoning has been used to suggest that consumers retained more than 70 per cent of the benefit.

(c) NIE submitted that, for the period April 1997 to March 2003, employees who took up its early retirement programme were on average 9.5 years from normal retirement age. Based on when those employees left NIE,[25] the average benefit to NIE from retained cost reductions was only 2.3 years.[26] Using an opex/capex profile for leavers of 70:30, NIE suggested that a 77:23 split between consumers and shareholders was most appropriate in this case.

(d) The UR submitted that, for the period April 1997 to March 2003, NIE retained 3.5 years of cost reductions, and that on average employees who took up the scheme were 8.5 years from retirement age. This suggested that NIE retained approximately 50 per cent of the benefit of the cost reductions in net present value terms.

12.46 Based on the additional submissions made by NIE and the UR with regard to the specific profile of those taking early retirement between 1997 and 2003, we judged that the specific circumstances of this case (as described in paragraph 12.45*(c)* and

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[24] Using an NPV calculation, the benefit to shareholders (in the early years) would have been more than 50 per cent.
[25] Those leaving earlier in the price control would generate a larger benefit as there is a greater time period until costs are reset at the next price control.
[26] NIE excluded those leavers anticipated in the MMC RP2 report. It said that this was because the RP2 revenue allowance took account of how much of the cost of such retirements should be borne by consumers.

(d) above) could support an attribution of ERDC costs to shareholders of between 23 and 45 per cent.[27]

12.47 Whilst the method used to apportion these liabilities was necessarily approximate, we did not find a method which we considered superior. We found that when applied to this case, the method could support a reasonably wide range of estimates (as noted, from 23 to 45 per cent of ERDC liabilities attributed to NIE). We judged that the current apportionment was broadly appropriate and within the range of reasonable estimates given the specific circumstances of this case.

12.48 We therefore decided that there was no reason to change the current ERDC attribution of 30 per cent to NIE shareholders and 70 per cent to consumers.

Past shareholder contributions and ERDCs

12.49 We considered NIE's submission that its previous shareholder contributions should be offset against its share of the ERDC liability. These shareholder contributions were made during and at the end of RP3.

12.50 NIE said that it was sufficient to know that these shareholder contributions had eliminated the deficit in 2007 and were today sufficient to cover NIE's share of ERDCs. It said that the 2007 special shareholder contribution was successful in its stated objective of clearing the deficit at the time. In its view, the UR's proposals would mean that shareholders were being asked to fund ERDC costs twice.[28]

12.51 The UR said that this was an attempt to rewrite history and that no link existed between these contributions and ERDCs. It said that the 2007 shareholder payment

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[27] 23 per cent assumes that 30 per cent of leavers are opex and excludes MMC leavers; 45 per cent assumes that 95 per cent of leavers are opex and includes MMC leavers. In each case, we assume 9.5 years remaining until retirement.
[28] NIE Supplementary Submission, 10 June 2012, Annex 8, paragraphs 3.1–3.8.

was made in the context of and motivated by the acquisition of Viridian Group (then NIE T&D's parent company) by Arcapita Bank. It had nothing to do with early retirement costs.[29]

12.52 We were not presented with evidence which showed that these contributions were linked to ERDCs and we did not believe that there was a conceptual reason why they should be attributed in this way. We therefore decided that there was no reason to offset these shareholder contributions against NIE's share of ERDCs.

Ongoing pension service costs

12.53 The ongoing service costs for NIE represent the cost of servicing its DB and DC pension schemes through employer contributions (ie not deficit repair). NIE said that its projection for RP5 was £11.1 million, equivalent to around £2.2 million a year.[30]

12.54 Our indirect cost benchmarking of NIE (see Section 8) included pension service costs. Our indirect cost allowance therefore includes an allowance for ongoing pension service costs. We therefore provisionally decided that no additional allowance for ongoing pension service costs was necessary because otherwise we would be double counting these costs (once within our benchmarked allowance and additionally within a separate pension service allowance). This is also consistent with our view that, wherever possible, pension service costs should be benchmarked. In future revenue controls, we would expect that any ongoing pension service cost benchmarking would also include any incremental deficit or surplus.

Conclusion

12.55 We provisionally decided that:

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[29] UR Supplementary Submission, 24 May 2013, paragraphs 19, 55, 58–60.
[30] NIE Statement of Case, Chapter 10, paragraph 1.2. The projection is based on a five-year price control period.

(a) Only the pension schemes which provide services exclusively to the regulated business of NIE should be included in our revenue control. These schemes are NIE Ltd and NIE Powerteam Ltd (see paragraphs 12.14 to 12.16).

(b) The deficits in the included schemes should be split into historic and incremental deficits using the Ofgem Pension RIGS methodology; the cut-off date for the historic deficit will be 31 March 2012). The historic deficit will be funded 100 per cent by consumers; any incremental deficit arising will be funded 100 per cent by NIE (see paragraphs 12.17 to 12.24).

(c) The historic deficit should be recovered over a period of 15 years, with NIE compensated for any financing costs incurred due to timing differences with the plan it agreed with its trustees. NIE's WACC should be used as the discount rate (see paragraphs 12.25 to 12.30).

(d) Deficit repair payments should be based on the scheme valuations as at 31 March 2012 and should be reviewed (and changed if necessary) following each triennial valuation. In addition, the payment profile should be reviewed if NIE's deficit repair payments to the scheme change significantly. In either case, any new deficit repair profile should be reflected as soon as possible in the revenue control (see paragraphs 12.31 to 12.35).

(e) NIE should be refunded its stranded pension costs from RP4 over a period of 15 years (see paragraphs 12.36 to 12.39).

(f) The current split of ERDC liabilities (30 per cent to shareholders; 70 per cent to consumers) should be retained. In future the ERDC liability will be calculated using the Ofgem Pension RIGS methodology.(see paragraphs 12.40 to 12.48).

(g) No adjustment to NIE's ERDC liability should be made for previous shareholder contributions (see paragraphs 12.49 and 12.50).

(h) NIE's ongoing pension service costs will be included in our indirect benchmarking and therefore no additional allowance is included. In future, we would expect that

benchmarking will include any incremental pension deficit (see paragraphs 12.52 and 12.53).

13. Allowed rate of return

Introduction

13.1 This section sets out the detail of our approach to assessing NIE's cost of capital for the period 1 April 2012 to 30 September 2017. It is structured as follows:

(a) comments on the general approach to cost of capital estimation and the position of the parties to this inquiry (paragraphs 13.2 to 13.30);

(b) gearing (paragraphs 13.31 to 13.38);

(c) the cost of debt and the evidence for a Northern-Ireland-specific premium (paragraphs 13.39 to 13.74);

(d) the cost of equity:

(i) arguments for a Northern-Ireland-specific premium (paragraphs 13.79 to 13.108);

(ii) the risk-free rate (RFR) (paragraphs 13.109 to 13.122);

(iii) the market return and the ERP (paragraphs 13.123 to 13.147); and

(iv) beta (paragraphs 13.148 to 13.170); and

(e) preliminary conclusions on the WACC (paragraphs 13.171 to 13.181).

General approach

13.2 Our approach is to base NIE's price cap on the revenue required by NIE to cover its efficiently-incurred costs, including a return on its RAB. We consider that its return on RAB should be equal to NIE's expected cost of capital. Allowing a return at this level is consistent with our duty to secure that the company is able to finance its licensed activities. In calculating return, the relevant costs are those projected for an efficiently managed company and may be above or below out-turn costs depending on whether the company is more or less efficient than the benchmark.

13.3 There are two initial issues:

(a) Which company's cost of capital is relevant—that of the regulated (licensed) company or its ultimate holding company?

(b) Which time period is relevant—the period for which we are determining the price cap (2012 to 2017) or the longer term?

Relevant company

13.4 NIE is a subsidiary of ESB, and is majority owned by the Irish Government.[1] However, under the existing regulatory regime for electricity, NIE is treated as a 'ring-fenced' company. In particular, NIE is required at all times to conduct its regulated business as if it were substantially a free-standing business and a separate public limited company. It is also required to take all appropriate steps to obtain and thereafter maintain at all times an investment grade credit rating.

13.5 We are therefore concerned with the cost of capital of NIE as a stand-alone 'ring-fenced' company.

Relevant period

13.6 We are calculating the required return over the period 1 April 2012 to 30 September 2017 and we think it is the expected cost of capital in that period that is relevant. Long-run averages are relevant only to the extent that they affect the cost of capital in that period. They may do so for two main reasons:

(a) Regulated companies finance long-life assets in part through the issue of fixed-rate debt with long maturity and the cost of existing fixed-rate (embedded) debt is affected by interest rates at the time the debt was issued.

(b) Asset prices and/or yields may have a tendency to revert to a longer-run mean value and, if so, past levels are relevant to estimating the expected level over the relevant period.

[1] 95 per cent of the shares are state owned. The remaining 5 per cent of the shares are owned by an Employee Share Ownership Trust (source: ESB Annual Report and Accounts 2012).

13.7 We noted that we were setting the cost of capital in the autumn of 2013 for a five-year period that began in April 2012. We therefore had the benefit of approximately 18 months of actual data.

Weighted average cost of capital

13.8 The cost of capital is a weighted average of two components:

(a) the cost of debt (c_d); and

(b) the cost of equity (c_e), which is the return required to induce the marginal investor to purchase shares in the business.

13.9 The weightings (gearing or g) reflect the relative importance of each type of financing in the company's capital structure:

Equation 1: $WACC = c_d.g + c_e.(1–g)$

13.10 Both the UR and NIE calculate a 'vanilla' WACC (combining a post-tax return on equity and a pre-tax return on debt)[2] and propose a separate allowance for projected Corporation Tax payments (where the projected tax payment is calculated within a financial model). We use the same approach. The total return on the RAB is shown in equation 2:

Equation 2: *(Required return/RAB) = WACC + (Tax/RAB)*

13.11 At the most general level, there are three potential approaches to estimating the WACC, which we discuss in turn:

(a) direct estimation of the company's cost of capital;

(b) direct estimation of the cost of capital of comparator companies; and

(c) model-based estimation of the company's cost of capital, either based on data for the company itself or comparators or both.

[2] As stated here, the WACC includes no corporate tax adjustment.. This is sometimes known as the 'vanilla WACC'. As we do not use any alternative definitions in this section, we simply refer to it as the 'WACC' (rather than the 'vanilla WACC').

Direct estimation

13.12 Payments on existing fixed-rate (embedded) debt are a known quantity, and the cost of floating-rate and new fixed-rate debt can be estimated from existing yields together with expected trends in interest rates.

13.13 NIE's equity is not quoted, so there is no current market information on its cost of equity. In any event, the cost of equity is much more difficult to estimate directly than the cost of debt, even for a quoted company where the marginal shareholders' current valuation (the market price of its shares) is known. This is because the marginal shareholders' expected future return (in the form of dividends and other payments) from holding the shares is not observable[3] and, under the type of incentive regulation applied in the UK and Northern Ireland to energy, water and other utilities, very difficult to estimate directly. In the USA, many utilities are still subject to cost of service regulation, and the cost of equity is more often estimated directly (by calculating the rate of return that equates the current value of a stock to the present value of its future stream of dividends).

Direct estimation for comparator companies

13.14 Data for comparator companies may be useful for two reasons. First, it may be available where there is no data for the company concerned. Second, even where there is individual company data, comparator company data may be relevant to assessing the costs that an efficient company would incur (in regard to the cost of capital as well as other areas of the price control, such as opex).

13.15 Current equity valuations are available for a small number of quoted GB utility companies: National Grid, SSE, United Utilities, Severn Trent and Pennon. National Grid and SSE are involved in gas and electricity transmission and distribution and are

[3] The expected future return also depends on future regulatory decisions.

regulated by Ofgem. United Utilities, Severn Trent and Pennon are water and sewerage companies and are regulated by Ofwat. In considering the relevance of such evidence to NIE, it is important to recognize that there are differences in the business activities, the customer base and the regulatory framework.

Model-based estimation

13.16 The advantage of model-based estimation is that it can provide additional relevant data (although necessarily based on assumptions about the working of capital markets). Given the availability of direct data on the cost of debt, model-based estimation is only relevant to the cost of equity. The main model discussed in this section is the capital asset pricing model (CAPM). NIE proposed an adjustment to the usual CAPM approach to allow a Northern-Ireland-specific premium on the cost of equity (see paragraph 13.79).

13.17 The CAPM relates the cost of equity to the RFR (r_f), the expected return on the market portfolio (r_m), and a firm-specific measure of investors' exposure to systematic risk (beta or β):

Equation 3: Cost of equity: $c_e = r_f + \beta \,.\, (r_m - r_f)$

Estimates of r_f, r_m and beta are required to estimate the cost of capital via the CAPM.

13.18 In our 2007 report on Heathrow and Gatwick,[4] we looked at alternatives to the CAPM and found that:

(a) CAPM remains the tool with the strongest theoretical underpinnings;

(b) it is not at all clear from the academic literature that other models have better predictive power, particularly when applied to UK companies; and

[4] *BAA Ltd: a report on the economic regulation of the London airport companies (Heathrow Airport Ltd and Gatwick Airport Ltd)*, CC, presented to the CAA on 28 September 2007.

(c) none of the alternative models helps to overcome the problems that CAPM has in dealing with limited market data.

13.19 We believe that these points remain valid. Hence, we also continue to believe that although the CAPM has its limitations, it is the most robust way for a regulator to measure the returns required by shareholders. Moreover, we have placed considerable weight on the CAPM in previous regulatory inquiries. Consistency and predictability of regulatory approaches is in the public interest.

13.20 Our projected cost of equity will therefore be based primarily on our estimates of four parameters: g, r_f, r_m and beta. These parameters can change as a result of movements in financial markets, whilst at the same time there is continuing work by financial and academic analysts on new data and on the reinterpretation of existing data. In addition, there can be considerable uncertainty over the appropriate level for some inputs. All these factors suggest to us that we should not approach the cost of capital calculation mechanistically, but will need to exercise a degree of judgement when selecting our parameters, and similarly in evaluating the outcomes and reaching our conclusions.

Inflation

13.21 We estimate the WACC in real terms, net of inflation. In doing so, it is sometimes necessary to derive real rates from nominal prices, for example yields on government and corporate debt. Because we are forecasting the WACC for the period 2012 to 2017, we use an estimate of inflation over this period to derive the corresponding real return.

13.22 Since NIE's price control is RPI–X based, we estimate a measure of RPI over the relevant period to ensure consistency across all aspects of the modelling. Using inconsistent inflation estimates could result in prices that are below those required to allow NIE to earn its cost of capital.

13.23 We note the following evidence on inflation over the relevant period:

(a) HM Treasury forecasts RPI at 3 per cent on average for 2013 and 2014.

(b) OBR forecasts an average of 3.0 for the same period. Its forecasts for 2015 to 2017 average 3.6 per cent.[5]

(c) Bank of England data on implied inflation calculated as the difference in yields between nominal and index-linked government bonds has varied between 2.3 and 3.2 per cent for bonds with a ten-year maturity over the year to August 2013.[6]

(d) We also note the Bank of England's CPI target of 2 per cent, which it expects to exceed for the next two years and then revert to the target rate. Historically there has been a wedge of around 0.8 per cent between CPI and RPI.

13.24 In this section we use a range for expected inflation over this period of 2.7 to 3.2 per cent.

The allowed rate of return under the current price control, RP4

13.25 During the current price control (RP4), covering the period from 1 April 2007, the rate of return has been set at two different points. The allowed WACC was 5.635 per cent until 31 March 2010, and about 0.2 per cent lower from 1 April 2010. This figures were based on Ofgem's electricity distribution and transmission price controls.

[5] Office of Budget Responsibility March 2013 report from http://budgetresponsibility.org.uk/economic-and-fiscal-outlook-march-2013/.
[6] Bank of England data from www.bankofengland.co.uk/statistics/Pages/yieldcurve/default.aspx.

UR and NIE's estimated cost of capital

13.26 Before discussing the components of the WACC, we set out the UR's and NIE's projected cost of capital for NIE (see Table 13.1).

TABLE 13.1 **Projected real cost of capital for RP5, 2012 to 2017**

	per cent	
	UR	*NIE*
Gearing	50.0	60.0
Cost of debt	3.4	3.6
WACC (vanilla WACC)	4.6	5.2
Cost of equity		
RFR	2.0	2.0
ERP* ($r_m - r_f$)	5.0	5.25
Equity beta†	0.74	0.9
Northern Ireland premium	0.0	1.0
Cost of equity	5.7	7.7

Source: UR Final Determination; UR Statement of Case, UR-7, paragraph 27; NIE Statement of Case, Table 15.4.

*Equity risk premium.
†In this table the difference in gearing tends to exaggerate the difference in beta—see discussion in cost of equity section in paragraphs 13.75 to 13.170 below.

13.27 The UR told us that it considered that its analysis that underpinned its original RP5 proposals was out of date and that several factors could lead the CC to allow lower returns than were included in its RP5 proposals. We consider the UR's points in further detail under the discussion of the relevant parameter of the WACC.

13.28 A comparison of elements in the WACC is not entirely straightforward because of the difference in gearing. This may affect the WACC in two ways:

(a) Higher gearing increases the riskiness of both debt and equity and therefore increases the required rate of return on both debt and equity. The effect on the WACC is at least partially offset because a higher weighting is attached to cheaper debt and a lower weighting is attached to more expensive equity.

(b) In principle, higher gearing reduces tax payments as higher gearing implies more debt and hence higher interest payments, and interest is tax deductible (this is known as the debt tax shield). However, both the UR and NIE calculate tax allowances from a financial model that projects forward from the company's

current actual gearing level, which (at about 50 per cent) is about the same as the level of gearing assumed in calculating the WACC (see Table 13.1). Thus, our understanding is that, under the UR's and NIE's modelling, a higher gearing in the WACC would not be associated with lower projected tax allowances in the price control model, because these allowances are projected on the basis of the actual level of gearing that is not affected by the gearing in the WACC.

13.29 Table 13.1 shows that NIE's estimated WACC is 60 basis points higher than the UR's. NIE's assumed cost of equity is 200 basis points higher than the UR's. NIE's assumed cost of debt is 20 basis points higher than the UR's. When adjusted for gearing, the UR's and NIE's beta assumptions are similar. The gearing assumption itself has a negligible effect (see Appendix 13.1).[7] The differences in the estimation of the cost of equity relate to the ERP (which affects the WACC by nine basis points) and the Northern Ireland premium (which affects the WACC by 40 basis points).

13.30 As we are redetermining NIE's price cap, we are not limited to considering only the submissions made by the UR and NIE when considering the appropriate WACC.

Gearing

13.31 In this subsection, we consider the gearing in the WACC (ie the 'g' in equation 1).

The UR

13.32 The UR used a gearing ratio of 50 per cent in its final proposals, based on NIE's actual gearing (measured as the ratio of the book value of debt to the RAV). The UR

[7] Here, and elsewhere in this section, in assessing changes in gearing we have had to make assumptions about NIE's debt beta. We have assumed a level of 0.1, but results do not tend to be sensitive to the level of debt beta. In light of this, we did not carry out work to assess the level of NIE's debt beta.

thought that this was the right starting point when NIE was about to enter a growth phase.[8]

13.33 The UR told us:[9]

> The Commission may want to investigate whether NIE T&D's starting level of gearing (i.e. approximately 50%) is appropriate; in much the same way as the Commission investigated the historical causes of Bristol Water's gearing level during the recent Bristol Water price control inquiry. If any such investigation were to reveal that avoidable shareholder distributions had added to NIE T&D's debts, thus limiting the business' capacity to fund new capex through borrowings in the current period, that may call into question the justification for allowing revenues to be brought forward now.

NIE

13.34 NIE proposed a range of 55 to 65 per cent for the gearing ratio with a point estimate of 60 per cent. Its estimates were informed by assumptions made by Ofgem in its 2009 and 2012 price control reviews for electricity and gas distribution and transmission networks.

13.35 NIE told us that it had consistently maintained its gearing below a threshold of 57.5 per cent set at the RP4 price control review.

CC discussion

13.36 Different levels of gearing may be associated with different levels of WACC and, in principle, an optimal level of gearing might be estimated by attempting to balance the different effects (including the risks and costs of any financial distress that might be

[8] UR Final Determination, paragraph 12.26.
[9] UR Statement of Case, UR-7, paragraph 43.

associated with higher gearing). After taking account of the tax effect, the WACC is not very sensitive to the level of gearing (see Appendix 13.2). Gearing may also affect financeability: see Section 16.

13.37 In our financial modelling, we start with NIE's current approximate level of gearing (around 50 per cent). This is thus the level that we have assumed for the purposes of calculating the WACC.

13.38 As regards the impact of gearing on tax payments, the CC has expressed a view in the past that tax payments should be projected on a basis that is consistent with the forecast WACC, including the gearing assumption in the WACC. As shown in Equation 2, the projection of tax payments is an integral part of the computation of required revenue and of the price cap. We need to make sure that the company can earn its cost of capital under our assumed gearing, and this requires there to be consistency between gearing in the WACC and in the tax modelling.[10]

Cost of debt

13.39 Our analysis of the cost of debt is structured as follows:

(a) We examine the costs of NIE's existing debt, including NIE's argument that there is a Northern Ireland debt premium.

(b) We examine the cost at which new debt might be raised during the price control period.

(c) We calculate the cost of debt as a weighted average of the estimated costs of existing and new debt.

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[10] See *Bristol Water* (2010). If the company reduces gearing to the notional level, it will incur higher tax payments than assumed in financial modelling, and its required return will be greater than assumed in financial modelling. Moreover, even if the company were able to continue with its higher gearing, its (vanilla) WACC will tend to be higher than assumed in financial modelling (see Appendix N) and its required return will consequently also be higher than assumed in financial modelling.

13.40 NIE's debt comprises primarily two bonds, on which a total value of £572 million was outstanding as at 31 June 2013.[11] There is no bank debt or intra-group liabilities.

13.41 Table 13.2 summarizes the parties' assumptions on the cost of debt.

TABLE 13.2 **Parties' assumptions on the real cost of debt**

	All debt %
UR's assumed cost of debt	
Cost of debt	3.4
NIE's assumed cost of debt	
Cost of debt	3.6

Source: UR Statement of Case, UR-7, paragraph 27; NIE Statement of Case, Chapter 15, paragraph 3.32.

The UR

13.42 The UR said that its RP5 proposals had assumed that any new borrowing would have the same cost as NIE's existing debt. It noted that the cost of debt had fallen since it made its RP5 proposals and that, with hindsight, this approach might over-state the cost of new borrowings.[12]

13.43 The UR said that the premium yield on NIE's debt had reduced and almost dis-appeared in late 2012 and early 2013, and that this had coincided with a financial restructuring by ESB, NIE's parent company, in 2012. According to the UR, this showed that the premium was caused by investor concern about ESB's weaker credit quality prior to the financial restructuring, and customers should not be required to pay for any adverse consequences of NIE's particular ownership structure.[13]

[11] NIE report and accounts for the six months ended 30 June 2013, www.nie.co.uk/documents/Annual-Reports/NIE-Interim-Accounts-Jun13-FINAL-clean.aspx, note 8.
[12] UR Statement of Case, UR-7, paragraph 9.
[13] UR Supplementary Submission, UR-26, paragraph 71.

13.44 The UR said that the cost of debt in NIE's proposals was higher than the yield on NIE's actual debt and that NIE was asking customers to pay £114 towards each £100 of interest that NIE actually incurred, and there was no good reason for that margin.

13.45 The UR said that if we were to allow NIE's embedded debt costs, there might be a case for disallowing a portion of NIE's actual interest costs so as to avoid a situation in which customers in Northern Ireland had to pay more for their electricity as a consequence of NIE's current ownership arrangements.

NIE

13.46 NIE's estimate of the cost of debt is based on Ofgem's DPCR5 benchmark for GB electricity networks of 3.6 per cent. NIE proposes to add a Northern Ireland premium in the range of 65 to 104 basis points (with a point estimate at the lower end of the range) calculated by reference to historical differences in yields between NIE's bond and comparators.

13.47 NIE said that there was empirical evidence that its bond due in 2026 (issued in 2011) had been trading at a substantial discount to comparable bonds issued by regulated electricity distributors elsewhere in the UK. The discount corresponding to a premium on the yield to redemption of the order of 65 to 104 basis points (based on 6- and 12-month averages[14] respectively). There was a reduction in the yield difference in late 2012.

13.48 NIE also argued that evidence of a Northern Ireland premium was apparent from an examination of yields on bonds issued by PNGL.

[14] Ended on 5 March 2013.

13.49 NIE sent us a paper by Frontier which estimated the premium to be 76 basis points. This was based on the average difference in yield between NIE's 2026 bond and that of a basket of comparable GB utility bonds, over a one-year period ended 1 June 2013.

13.50 NIE disputed the UR's view that there was a connection between the premium and ESB's ownership of NIE. It said that because the bond was secured on NIE's licensed business, its market price reflected risks associated only with NIE itself. NIE said that the fall in NIE's bond yield occurred several months after the completion of ESB's refinancing and this meant that it was unlikely that the two events would be linked.

13.51 NIE raised the following questions, which, it said, undermined the UR's position that the premium was a consequence of ESB's ownership:[15]

(a) Why was there a premium on NIE's short-dated bond before NIE was purchased by ESB?

(b) Why was there a premium on NIE's short-dated bond even before the Irish debt crisis led to spikes in the yields on Irish government debt?

(c) Why is there a similar premium observed on the bond issued by Phoenix Natural Gas Ltd (PNGL), which has no links to ESB?

(d) Why has the SEM Committee, which includes three representatives from the UR, decided to take account of a 'risk premium' that reflects 'spread differentials between NIE and UK utility bonds' in its decision paper on new entrant costs if it believes that this spread only arises as a consequence of ESB's ownership of NIE and therefore does not apply more generally?

[15] NIE supplementary submission, p144, paragraph 3.5.

The SEM Committee

13.52 The SEM Committee, a joint committee of the UR and its Republic of Ireland counterpart which determines some parameters affecting electricity wholesale markets across the island of Ireland, has allowed a Northern Ireland premium of 50 basis points in estimating the financing costs that a hypothetical new peaking power station would incur.[16]

Previous CC inquiries

13.53 In recent regulatory inquiries,[17] the CC indicated that it would normally factor a measure of existing 'embedded' fixed-rate debt costs into its calculation of the cost of debt. We therefore propose to calculate the cost of debt as a weighted average of the cost of existing debt and the cost of new debt (with the amount of new debt depending on the assumed level of gearing).

CC discussion

13.54 We consider that there are three elements to the cost of debt:

(a) the cost of existing fixed-rate (embedded) debt;[18]

(b) the cost of existing and new floating-rate debt (which depends on short-term interest rates during the price control period, as well as the relevant spread over government debt); and

(c) the cost of new fixed-rate debt (which depends on interest rates for this duration and type of debt at the time of issue, as well as the relevant spread over government debt).

Each of these three elements should be weighted according to its projected importance in the company's overall debt during the projection period. Among the points we

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[16] Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Calendar Year 2013, Decision Paper, 31 August 2012.
[17] *Bristol Water plc* (2010); *BAA Ltd* (2007 report on Heathrow and Gatwick, op cit) and *Stansted Airport Limited, Q5 price control review*, CC, presented to the CAA on 23 October 2008.
[18] This is relevant except to the extent that it matures prior to the end of the price-cap period.

considered was whether the relative importance of floating and new fixed-rate debt should depend on longer-run costs as well as which was expected to be cheapest during the price-cap period. For instance, during a period of low interest rates, floating-rate debt might be expected to be cheaper than longer-dated new fixed-rate debt, but it may nevertheless be reasonable to issue longer-dated fixed-rate debt if short- and longer-run interest rates are expected to increase (and hence there is a cost to delaying issue of fixed-rate debt).

13.55 There are two approaches to the cost of existing fixed-rate debt:

(a) Set the rate based on an average rate derived from an appropriate index over a period prior to the price control period. This has the advantage of giving companies incentives to reduce the cost of their debt to outperform the index. Ofgem has recently moved to such an approach using a ten-year trailing average index for A and BBB rated bonds with maturities over ten years.

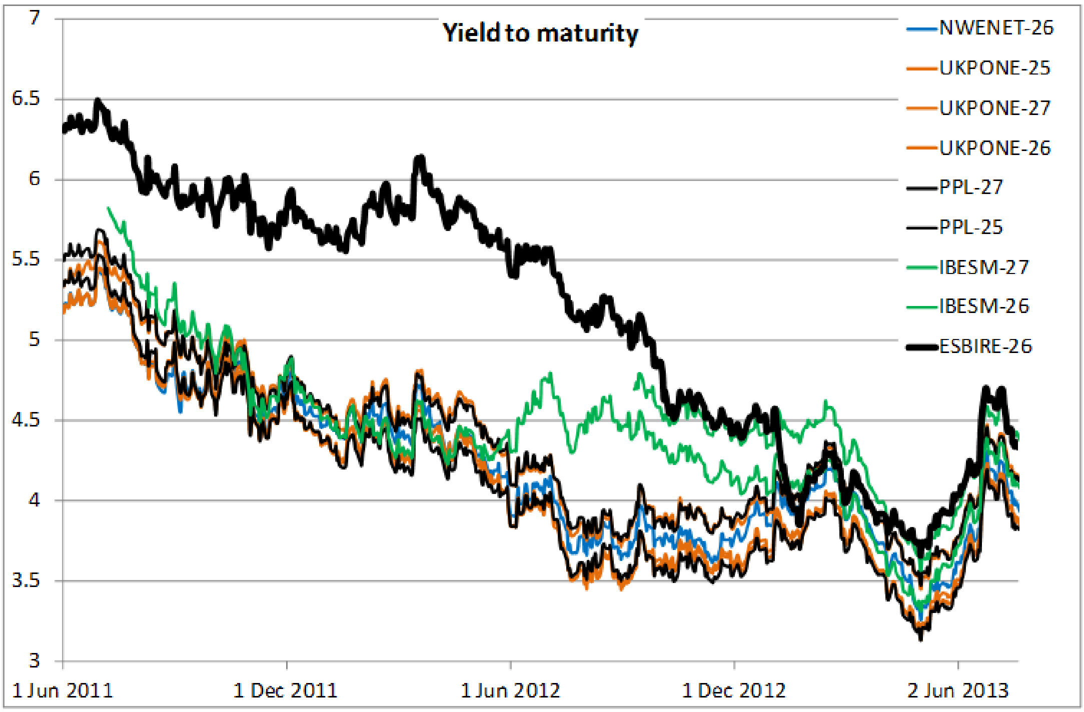
(b) Set the rate based on the actual cost of NIE's embedded debt. If used as a general approach, this would give NIE weaker incentives to reduce its cost of debt, particularly towards the end of price-cap periods.

13.56 We have not considered adopting a debt indexation approach in this inquiry, because we consider that it is a policy decision that requires pre-notification in order that the regulated company can make appropriate financing decisions. Accordingly we propose to estimate the cost of embedded debt based on NIE's actual debt.

The case for a Northern-Ireland-specific risk premium

13.57 Figure 13.1 shows the yield to maturity on NIE's 2026 bond and comparable bonds issued by GB electricity distribution companies. The chart starts on the date at which NIE's 2026 bond was issued.

FIGURE 13.1



Key:

ESBIRE-25	NIE Finance 6.375% due 2 June 2026 (BBB+)
NWENET-26	Electricity North West 8.875% due 25 March 2026 (BBB+)
UKPONE-25	Eastern Power Networks 6.5% due 31 March 2025 (BBB+)
UKPONE-27	London Power Networks 6.125% due 7 June 2027 (BBB+)
UKPONE-26	South Eastern Power Networks 5.5% due 5 June 2026 (BBB+)
PPL-27	Western Power Distribution South West 5.875% due 25 March 2027 (BBB+)
PPL-25	Western Power Distribution West Midlands 6% due 9 May 2025 (BBB+)
IBESM-26	SPD Finance UK 5.875% due 17 July 2026 (BBB)
IBESM-27	SP Manweb 4.875% due 20 September 2027 (BBB)

Source: Bloomberg.

13.58 We noted that there was a difference in yields of more than 100 basis points for most of 2011 and 2012. Since January 2013 the difference in yields has reduced to between 0 and 50 basis points.

13.59 We have considered the possibility that the difference in yields might be in some way associated with ESB's ownership of NIE. ESB conducted a financial restructuring in late 2012. The events highlighted on ESB's website are:

(a) 4 September 2012: ESB prices bond in market (€600 million with five-year maturity).

(b) 12 November 2012: ESB issues €500 million bond (seven-year maturity).

(c) 31 January 2013: ESB welcomes revised outlook from Fitch Ratings.

(d) 13 February 2012: ESB signs new €1.35 billion bank credit facility.

(e) 13 February 2013: Standard and Poor's improves outlook for ESB and NIE.

13.60 We have examined price data for ESB's bonds in pounds, euros and US dollars, and for comparator UK, German and US government bonds. Whilst we found no other large price movements on the specific days in January 2013 where NIE's bond yield fell relative to comparable bonds, we observe that, at a broader level, the premium on ESB bonds was particularly high at the time where the NIE premium was high, and that the falls in the ESB premium and the NIE premium took place within months of each other.

13.61 There are few reported trades in NIE's bond. The daily price data that we have used reflects bids and offers published by market makers rather than actual transactions. We cannot rule out the possibility that the timing differences were simply due to a lack of market efficiency in these quoted prices.

Provisional determination on Northern Ireland premium and the cost of existing debt

13.62 We accept that there appears to be a premium in the yield on NIE's debt compared with comparable instruments issued by other electricity distribution companies in the UK.

13.63 We do not rule out the possibility that the premium, which was at its greatest in 2011 and 2012, was in part caused by market concern about ESB, which was alleviated following ESB's successful refinancing in the latter part of the calendar year 2012. To the extent that this is the cause, then we would agree with the UR that it should not be reflected in price limits. But we are not certain to what extent the premium can be attributed to ESB ownership.

13.64 It is our provisional view that the cost of NIE's existing debt should be assessed based on the actual cost of NIE's outstanding bonds.

13.65 There are two bonds secured on NIE's licensed transmission and distribution business: a £175 million bond maturing 2018 with a coupon rate of 6.875 per cent; and a £400 million bond maturing 2026 with a coupon rate of 6.375 per cent. The weighted average cost of this existing debt is 6.5 per cent nominal. The 2026 bond is listed on the London Stock Exchange.

13.66 We therefore assume a real cost of existing debt of 3.7 per cent based on inflation of 2.8 per cent.

The cost of new debt

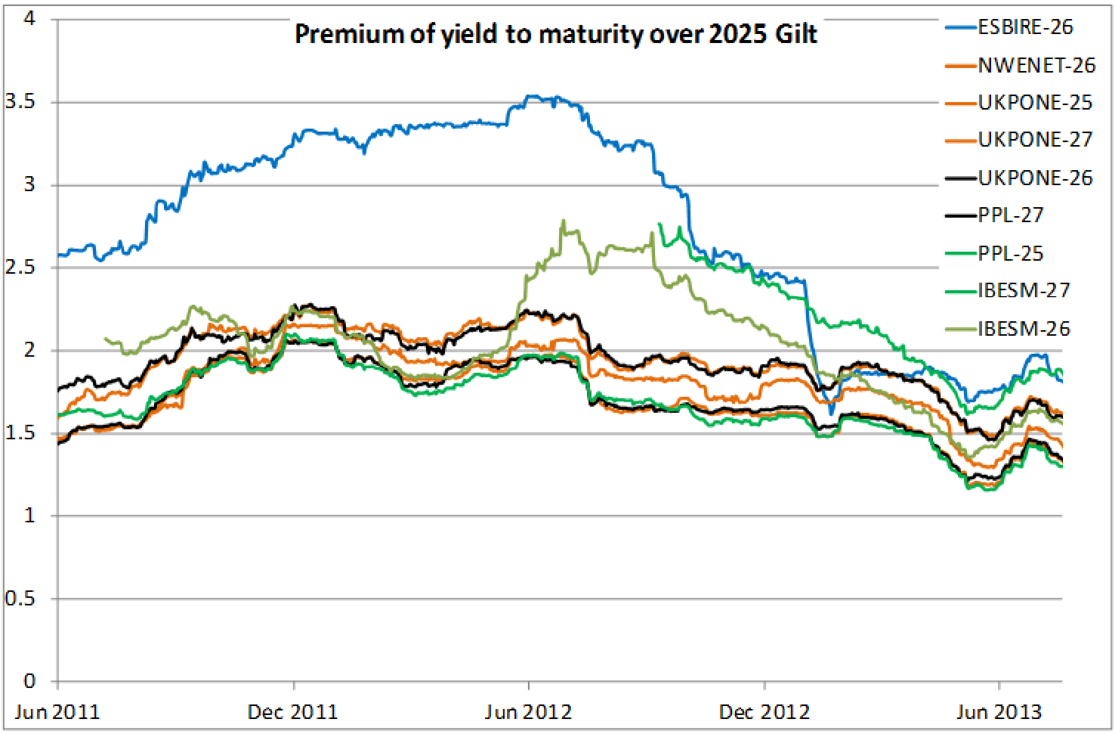
13.67 Our approach to estimating the cost of new debt was to:

(a) Consider the yield to maturity on NIE's £400 million bond: this is equivalent to the return that an investor would earn by purchasing an NIE bond now and holding it until the capital is repaid in 2026. This provides a proxy for the rate at which NIE could borrow now if it was offering a fixed rate to 2026. As of August 2013, the yield to maturity on NIE's 2026 bond was around 4.4 per cent, a spread of around 165 basis points over the benchmark gilt yield.

(b) We examine market data for publicly traded bonds and recent new issues and compare this benchmark data to the indications of pricing that NIE supplied in its Statement of Case.

13.68 In Figure 13.2 we plot the yield spread of NIE and comparator bonds over a benchmark UK government gilt.

FIGURE 13.2



Source: Bloomberg.

13.69 Figure 13.2 indicates that there have been significant fluctuations in the spread of NIE's bond over the past few years, which reached 3.5 per cent in the middle of 2012. Most of that variability is associated with fluctuations in the apparent Northern Ireland premium until January 2013. The spread of comparator bonds issued by other UK electricity distribution companies has generally remained between 1 and 2.5 per cent throughout the period, and the spread on all the bonds (including NIE's) is now below 2 per cent. NIE's bond is trading at the upper end of the range of comparator bonds.

13.70 The yield curve for government securities slopes upward (see Figures 13.3 and 13.4); thus, debt with a maturity of less than ten years might be cheaper than longer-dated debt. But this effect is modest and we do not think that we need to estimate the term of new NIE debt in order to reach a view on its likely cost.

13.71 We considered recent bond issues by GB utilities in the ratings category BBB+ and BBB—see Table 13.3. We found that recent issues of nominal debt by utility companies rated BBB+ or BBB were priced at coupons of between 3.6 and 5.9 per cent and were trading at yields in the range of 3.3 to 4.6 per cent. We concentrated on nominal debt as we considered it unlikely that NIE would be able to raise index-linked debt.

TABLE 13.3 **Selected nominal bond issues by UK utility companies since June 2011**

Issuing company	*Composite rating*	*Coupon*	*Maturity*	*Currency*	*Amount £m*	*Issue date*	*Yield 30/9/13*
Yorkshire Water Services Bradford Finance Ltd	BBB	4.965	13/06/2033	GBP	90	12/06/2013	N/A
Anglian Water Services Financing PLC	BBB	4.500	22/02/2026	GBP	200	22/02/2013	4.621
Severn Trent Utilities Finance PLC	BBB+	3.625	16/01/2026	GBP	500	16/01/2013	3.912
SP Manweb PLC	BBB	4.875	20/09/2027	GBP	350	20/09/2012	4.579
Severn Trent Utilities Finance PLC	BBB+	4.875	24/01/2042	GBP	250	24/01/2012	4.520
Wessex Water Services Finance PLC	BBB+	4.000	24/09/2021	GBP	300	24/01/2012	3.306
Southern Gas Networks PLC	BBB	4.875	05/10/2023	GBP	300	05/10/2011	3.725
Eastern Power Networks PLC	BBB+	4.750	30/09/2021	GBP	400	04/10/2011	3.352
SPD Finance UK PLC	BBB	5.875	17/07/2026	GBP	350	18/07/2011	4.356
South Eastern Power Networks PLC	BBB+	5.625	30/09/2030	GBP	200	17/06/2011	4.348
London Power Networks PLC	BBB+	5.125	31/03/2023	GBP	250	17/06/2011	3.709

Source: Bloomberg.

13.72 We considered that the cost of new debt for NIE might be higher than that of the BBB+ and BBB-rated utility companies due to NIE's small size relative to some of these utilities.

13.73 Taking the current spread of NIE's 2026 bond over gilts risks setting the cost of new debt too low as we cannot be certain that the differential in spreads that has been observed historically will not re-emerge in the remainder of RP5. We have therefore estimated a range for the cost of new debt that incorporates a spread of between 165 and 250 basis points over gilts. The upper end of this range reflects the average spread over a 12-month period since June 2012. In addition to this spread, we estimate that an additional 10 basis points should be added to cover issuance costs and fees. These spreads need to be combined with our estimates for gilt yields to calculate the total cost of debt. As discussed below, the current yield curves for longer-dated gilts (both nominal and index linked) do not suggest an expectation of an increase in yields during the price control period. For maturities of 15 years and over, nominal yields are between about 3.0 and 3.7 per cent (see Figure 13.4 below). Based on these gilt yields, spreads, issue costs and cash costs together with an assumed range for RPI inflation of between 2.7 and 3.2 per cent[19] over the relevant period, we estimate an range of 1.7 to 3.7 per cent and we take our point estimate as the average real cost for new longer-dated debt of 2.7 per cent (see Table 13.4).

TABLE 13.4 **Summary of CC assumptions on the cost of new debt**

	Lower	*Upper*	*Average*
Benchmark gilt yield	3.00	3.70	
Spread	1.65	2.50	
Implied coupon	4.65	6.20	
RPI inflation rate	3.20	2.70	
Real interest rate†	1.41	3.41	
Issue fees	0.10	0.10	
Cash cost‡	0.20	0.20	
Total	1.71	3.71	2.7

Source: CC calculations.

*See footnote to paragraph 13.55.
†Calculated using Fisher Equation: (1+coupon)/(1+inflation)–1.
‡The cash cost is the net cost of finance for cash balances held because debt needs to be raised ahead of capital expenditure.

13.74 We therefore take the real cost of existing debt to be 3.6 per cent and project a real cost of new debt of 2.7 per cent. On this basis, we use a working assumption for the cost weighted average real cost of debt of 3.4 per cent for the period, assuming 80 per cent embedded and 20 per cent new debt.

[19] See paragraph 13.24.

Cost of equity

13.75 Under the CAPM model, the cost of equity depends on the RFR, the ERP (that is the difference between the market return and the RFR, $(r_m - r_f)$ in equation 3) and the value of beta.

13.76 NIE submitted that its cost of equity should be subject to a Northern Ireland premium. We address this point first before analysing the RFR, the ERP and beta in turn.

A Northern Ireland equity premium?

The UR

13.77 The UR told us that NIE was wrong to seek a return on equity above the CAPM estimate.[20]

13.78 As regards the argument based on a comparison with the additional income opportunities available to electricity distribution network operators elsewhere in the UK, the UR pointed out that NIE had not been subject to the requirements of the incentive schemes under which these income opportunities arose; and that in any event the NIE price control should reflect the costs of financing NIE's business, not the profits made by other companies.

13.79 As regards the argument based on an inference from a Northern Ireland premium on the cost of debt, the UR disputed that such a premium existed. It also said that any Northern-Ireland-specific risk factors that might underpin a higher cost of debt would be diversifiable and so do not need to be compensated by higher expected rates of

[20] UR Statement of Case, UR-7, paragraph 28.

return. The UR said that its position was consistent with the position taken by the Monopolies and Mergers Commission in its 1997 inquiry on NIE price controls.[21]

NIE

13.80 In NIE's Statement of Case, the estimated cost of equity is obtained by adding a premium of about 1.0 per cent to the results of a calculation based on Ofgem's CAPM approach.[22]

13.81 NIE told us that this premium was required to reflect both the effect of the asymmetric calibration of certain incentive schemes introduced by Ofgem in the 2009 electricity distribution price control review, which increased expected returns to other UK electricity distribution companies above the headline allowed rate of return if these companies could meet, not beat, their targets; and the implication for equity of the observed premium on the yield of NIE's debt compared with electricity distribution companies elsewhere in the UK.

13.82 NIE told us that a Northern Ireland premium on the cost of debt justifies a premium on the cost of equity. We understand its reasoning to be based on the following steps:

(a) Debt and equity are 'contingent claims on the same productive underlying assets'. This means that the systematic risk drivers that give rise to a premium on the cost of debt must also give rise to a premium on the cost of equity.

(b) The spread between the yield on NIE's bonds and the yield on comparable bonds issued by GB utilities shows that there must be higher risks attributable to operating networks in Northern Ireland.

[21] ibid, paragraph 21.
[22] NIE Statement of Case, Chapter 15, paragraphs 3.22–3.29.

(c) NIE's equity investors should be remunerated for bearing the part of these underlying risks that falls on equity, where those risks are systematic rather than diversifiable.

13.83 NIE sent us a paper by Frontier which sought to explain that the premium on the cost of equity that it had proposed was conservative.

13.84 The paper analyses the link between a cost of debt premium and a cost of equity premium on the basis of a decomposition of the cost of debt premium of NIE compared with similar companies elsewhere in the UK. Frontier estimated the premium to be 76 basis points, using a one-year average to 1 June 2013.

13.85 Frontier assumed that there was no default risk premium element, because the NIE bond and the comparator bonds used in its analysis had equivalent credit ratings.

13.86 Frontier analysed the premium on the cost of debt as follows:

(a) a liquidity risk premium of 29 basis points or less; and

(b) a systematic risk premium, which is therefore at least approximately 47 basis points.

13.87 Frontier described the systematic risk premium as representing compensation to bondholders for bearing the non-diversifiable risk associated with corporate bonds.

13.88 Frontier estimated a cost of equity premium by multiplying the estimated systematic risk premium on debt, 47 basis points, by estimates that it drew from the academic literature of the elasticity of equity with respect to debt. The elasticity estimates ranged from 6 to 14, but Frontier only used figures between 6 and 12.4. This gives estimates of the cost of equity premium between 280 and 580 basis points, which is higher than what NIE had used in its calculations.

PNGL submission

13.89 PNGL sent us a paper by Professor Ian Cooper which provided theories as to how a Northern Ireland premium on the cost of debt might be reflected in a Northern Ireland premium on the cost of equity.

13.90 The report by Professor Ian Cooper included in the PNGL submission provides a detailed analysis of the possible basis for such a Northern Ireland premium on the cost of equity.

13.91 The analysis uses a decomposition of the debt premium in three parts:

(a) Premium to compensate for default risk, if any. This is the part of the premium that would be related to investors' perception of a higher expected default loss on Northern Ireland bonds than on comparator.

(b) Premium return for systematic risk, if any. This would be a premium return required by investors if there was a higher systematic risk in holding Northern Ireland bonds than comparator non-Northern-Ireland bonds.

(c) Premium due to other factors, if any. This could include, for example, illiquidity, which would impose costs on debt investors by making the secondary market less useful.

13.92 Professor Cooper argued that it was legitimate to uplift the allowed cost of equity if there was a premium on the cost of debt due to default risk. Whilst in principle it might be better to make an explicit cost allowance for the (asymmetric) risk of default, in practice it was reasonable to incorporate that allowance in the allowed cost of equity. To quantify the effect, Professor Cooper relied on a statistic that the average loss percentage on a debt default was 59 per cent, and an assumption that a debt default would be associated with a 100 per cent loss for equity investors. Looking only at this risk, the compensation to equity investors for default risk should therefore be 1.69 (=1/0.59) times the corresponding element of the premium on the cost of debt. This calculation is on the basis that Northern-Ireland-specific uncertainty is a downside risk (ie that it is not compensated by a upside potential for equity). Professor Cooper argued that this was an appropriate description of the additional risk in Northern Ireland because he attributed the premium to higher regulatory uncertainty and the immaturity of the regulatory process in Northern Ireland.

13.93 With respect to any part of the premium on the cost of debt attributable to systematic risk, Professor Cooper calculated that each 1 basis point element on the cost of debt was associated with 6.79 basis points on the cost of equity. This calculation relied on the assumption that the relevant element of systematic risk associated with holding debt and equity derived from a single underlying element of systematic risk in the business (rather than, for example, from a systematic element in the way in which a non-systematic risk was shared between equity and debt investors). Professor Cooper cited an estimate that 51.5 per cent of the spread of corporate bond yields over government securities was attributable to systematic risk rather than default risk; if this allocation could be applied to the Northern Ireland premium element of the spread, then each 1 basis point premium on the cost of debt would therefore translate to a 3.49 basis point premium on the cost of equity. Professor Cooper said that this multiplier might be reduced if only part of the non-default element debt premium was associated with systematic risk.

13.94 Professor Cooper did not infer any cost of equity premium from a premium on other (non-default non-systematic) risks.

Further points raised by parties in submissions

13.95 In response to Frontier's paper, the UR drew our attention to the fact that Frontier was silent on the question of how the higher exposure to non-diversifiable systematic risk to which it attributed part of the cost of debt premium had come about.

13.96 In response, Frontier emphasized what it saw as empirical evidence for a difference in systematic risk, suggested that NIE bore higher regulatory risk than other UK electricity distribution networks in part because of a shorter regulatory period, and that this regulatory risk was pro-cyclical in part because of a tendency for regulatory decisions to be tougher during recessions so that regulated companies would 'share the pain' of the wider economy.

13.97 The UR also thought that Frontier had not established the absence of a default risk element; and that there was a risk of a pick-and-mix error in adopting NIE's approach in a context where the allowed cost of debt included any Northern-Ireland-specific premium.

13.98 In response, Frontier told us that its approach to controlling for differences in default risk using credit ratings was appropriate and was very similar to an approach adopted by the CC in its 2008 Stansted price control inquiry, and that it was implausible that the Northern Ireland premium could be attributed entirely to default risk and illiquidity because that would imply that NIE's credit rating differed by several notches from what would reflect default risk.

13.99 The UR told us that PNGL was in the process of changing ownership at a reported premium to its regulatory asset value, and suggested that the real-life behaviour of investors was more significant than theoretical arguments about alleged Northern-Ireland-specific risks.

Discussion

13.100 The theories put forward by NIE, PNGL and Frontier to infer a cost of equity premium from a cost of debt premium all rely on the assumption that part of any premium on the cost of debt is appropriately modelled as debt investors' share of an underlying risk associated with NIE's business which is higher than for comparators; and that equity investors would bear, and expect to be remunerated for, their share of the same underlying risk.

13.101 The estimates of the cost of equity premium derived in this way are proportionately greater than the part of the cost of debt premium which is attributed to remuneration for financial risk (default risk or systematic risk, depending on the theory). This makes sense within these theories: equity investors are exposed to a greater share of an underlying business asset value risk than debt investors.

13.102 We do not think that we can rely on any of these theories in order to adjust our estimates of NIE's cost of equity.

13.103 This is because there is a possibility that any higher risk that bondholders bear (or perceive that they bear) might be offset by lower risk borne by equity holders. In other words, it is possible that, instead of being a consequence of a higher underlying business risk, any higher risk borne by debt holders might be merely the result of a different allocation in the case of NIE of an equivalent business risk between equity and debt.

13.104 If it were the case that the additional risk reflected in NIE's higher cost of debt was connected with a lower risk borne by equity investors, then a cost of debt premium would imply a reduction in NIE's cost of equity—the opposite of the theories put forward by NIE, PNGL and Frontier. Such a rebalancing of perceived risk between debt and equity could have occurred if NIE's bondholders perceived a risk that ESB, at the time where it might have been perceived as under financial stress, might have attempted to rely on NIE's cash flows to finance itself; that might have led to a perception that risks were being imposed on NIE bondholders in order to finance the wider ESB group. But we do not think that it would be appropriate to rely on such a theory given the regulatory ring-fencing obligations that NIE is subject to.

13.105 Since January 2013, the cost of debt premium may be not significantly higher than Frontier's highest estimate of a liquidity premium. There is therefore also a possibility that the yield on NIE's bonds is no longer indicative of any additional risk perceived by bondholders compared with similar companies elsewhere in the UK, and therefore than none of the theories outlined above applies.

13.106 NIE tried to demonstrate that there were factors which could, under some hypotheses, suggest that it should be allowed a higher return on equity than that suggested by standard CAPM comparisons.

13.107 We consider that the hypotheses on which the theories put forward by NIE and PNGL implicitly rest are plausible in theory but that equally plausible theories exist that would have different implications for the cost of equity. NIE's theory is not sufficiently supported by evidence for us to place weight on it.

13.108 It is our provisional view that the cost of equity should be calculated on the basis of the standard CAPM with no adjustment for a Northern Ireland premium.

Risk-free rate used to calculate the cost of equity

The UR

13.109 The UR said that the RFR used in the CAPM might now appropriately be set to a level lower than 2 per cent. Reasons included negative yields on index-linked gilts, and the fact that forecasts of RPI-measured inflation but not CPI-measured inflation had shifted up.[23]

NIE

13.110 NIE said that it considered an RFR of 2 per cent above RPI, as had been proposed by the UR in its RP5 proposals, was appropriate. NIE thought that setting the real RFR at this level would ensure consistency with Ofgem's DPCR5 determination and was consistent with taking a long-term view of market parameters during periods of anomalous economic activity, and that this would be sound regulatory practice.[24]

Previous CC inquiries

13.111 Since 2000, the CC has taken the view that long-dated index-linked gilt yields are in principle the most suitable basis for estimating the RFR applicable to the cost of equity. The CC has, however, considered that long-dated index-linked gilt yields have been affected by distortions (associated, for example, with pension fund dynamics) and that these need to be corrected in estimating the RFR applicable to the cost of equity. The CC has reached a judgement about the RFR on the basis of medium- and shorter-dated index-linked gilt yields.

13.112 At the time of the Stansted report, index-linked gilt yields were mostly yielding below 2 per cent. The CC concluded that there was no mechanistic way of interpreting the data and that it was required to exercise a certain amount of judgement before selecting a precise value for the RFR. Its judgement was that the RFR in recent years

[23] UR Statement of Case, UR-7, paragraph 16.
[24] NIE Statement of Case, Chapter 15, paragraph 3.18.

had been approximately 2.0 per cent, and that this was an appropriate assumption to use for 2009/10 to 2013/14.[25]

13.113 In its Bristol Water price determination, the CC used a range of 1 to 2 per cent, noting that market data on long index-linked gilts supported the lower end of this range.[26]

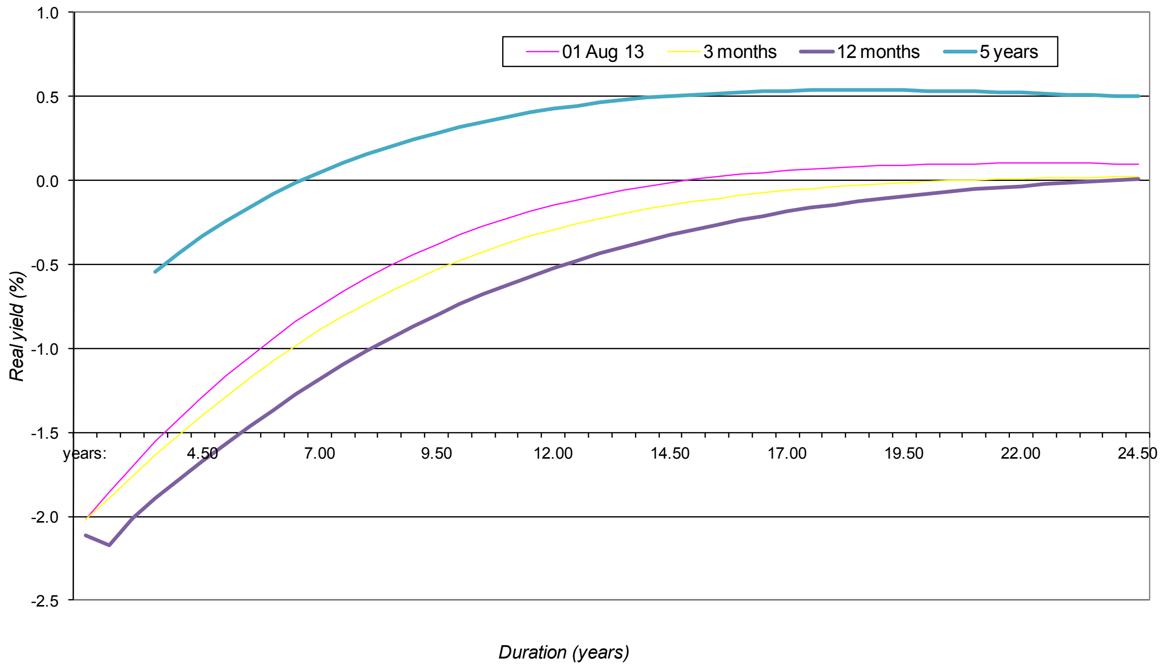
Discussion

13.114 We continue to regard index-linked gilt yields as in principle the most suitable source for estimating the RFR, since index-linked gilts have negligible default and inflation risk. Long maturities appear most relevant to the RFR in the cost of equity since equities also have long (indefinite) maturity. Figure 13.2 shows the index-linked yield curve for recent periods. For maturities of 15 years and more, the current index-linked yield curve is roughly flat at 0 per cent—the same yield curve derived by averaging yields over the last five years is about 0.5 per cent. Shorter-dated yields have fallen significantly over the last five years, reflecting action by the authorities to address the credit crunch and recession, and are currently very low.

[25] CC, 2008, Stansted Airport, paragraph 11.29.
[26] Bristol Water, 2010, Appendix N, paragraphs 66–74.

FIGURE 3

Index-linked yield curve

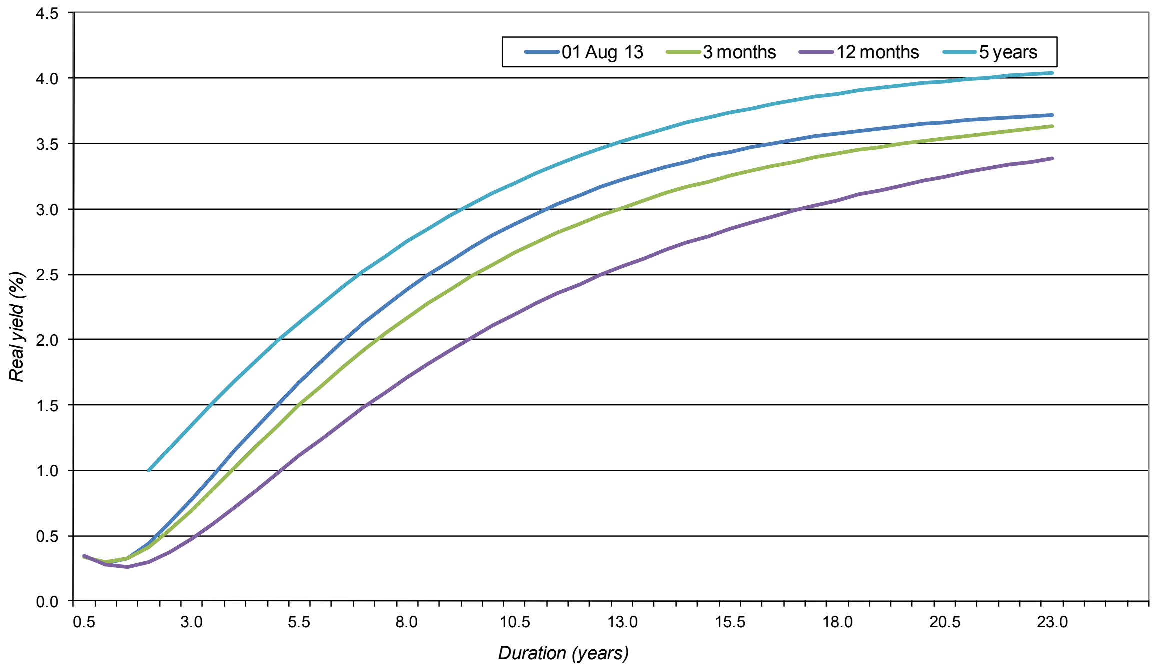


Source: Bank of England, implied real spot yield curve data.
Note: The four lines show average yields for August 2013, the three-month period from June to August 2013, the 12-month period from September 2012 to August 2013, and the five-year period from September 2008 to August 2013.

13.115 Nominal gilts also have negligible default risk, but are subject to inflation risk. Nominal gilt yields can be used to estimate a real RFR if assumptions are made about expected inflation and any inflation risk premium. Figure 13.3 shows nominal gilt yields on a similar basis to Figure 13.2. The nominal yield curve is upward sloping with yields of around 0.5 to 1 per cent on short-dated instruments and around 3 to 4 per cent on longer-dated gilts of maturities above ten years.

FIGURE 4

Nominal yield curve (spot)



Source: Bank of England, UK nominal spot curve data.
Note: The four lines show average yields for August 2013, the three-month period from June to August 2013, the 12-month period from September 2012 to August 2013, and the five-year period from September 2008 to August 2013.

13.116 We also considered long-run measures of returns on different asset classes as set out in Table 13.5.

TABLE 13.5 **Long-run realized real returns for different UK asset classes**

	Barclays 1899–2012	*Credit Suisse Geometric mean 1900–2012*	*Credit Suisse Arithmetic mean 1900–2012*
Gilts	1.3	1.5	2.4
Bills or cash	0.9	0.9	1.1

Source: Barclays Capital Equity Gilt Study 2013, Credit Suisse Global Investment Yearbook 2013.

CC discussion

13.117 In previous reports in the last ten years, the CC has paid attention to distortions in the index-linked markets that may affect the shape of the yield curve. In Bristol Water (2010), we noted that shorter-dated index-linked yields were affected by action by the authorities to address the credit crunch and recession and were therefore less relevant to estimating the RFR. In inquiries prior to 2010 we put less weight on longer-dated maturities, noting possible distortion from pension fund asset allocation policies.

13.118 We note that the effects of monetary policies and pension fund dynamics are increasingly well understood by the markets. Consequently we expect the market prices of ILGs to effectively incorporate expectations of the effects of these factors and therefore to provide a reasonable guide to future returns.

13.119 We note the view of Elroy Dimson, Paul Marsh and Mike Staunton in the 2013 edition of the Credit Suisse Global Investment Returns Yearbook:

> Today's low yields partly reflect the quest for safe havens, are heavily influenced by central bank policies, and may be affected by regulatory pressure on pension-fund and insurance-company asset allocations. They may also be impacted by demographic factors, such as dissaving by retiring baby boomers, but the evidence here is, at best, weak (see Poterba, 2001) Should we be concerned that today's long bond yields may be artificially low?
>
> This question is hard to resolve conclusively, but two points are relevant. First, many alleged 'distortions' are likely to be permanent. Regulatory pressures on insurers and pension funds are unlikely to diminish; pension funds are maturing and should lean towards higher bond weightings; baby-boomer retirement is ongoing; and, with a stock market that could easily see an increase in volatility …, the safe-haven demand for bonds could even increase.
>
> Second, these factors are all common knowledge. While the impact of quantitative easing (QE) and other unconventional monetary policies may be hard to measure, the policies themselves are disclosed and

transparent. It would be curious, therefore, if the market prices of bonds of different maturities failed to incorporate expectations of the impact of these factors. We should therefore expect bond market prices and yields to provide a reasonable guide to prospective returns.

13.120 It is plausible that index-linked gilt yields are artificially low due to the imperfections associated with RPI as a measure of underlying inflation. We note the historical gap between RPI and CPI measures of inflation of around 0.8 per cent, and the forecast increase in the gap to above 1 per cent . To the extent that CPI better reflects underlying inflation, measures of return relative to RPI (of which index-linked gilts are one such measure) may be artificially reduced as a result of that gap. This may be a factor behind negative short-term real yields, as would lower expectations of economic growth.

13.121 Long-dated index-linked yields have remained below 1 per cent for at least the last five years (see Figure 13.3). The prolonged period of low yields may suggest that long-run rather than temporary factors are at work. We therefore now see some grounds for assuming a lower RFR, more in line with actual long-dated index-linked yields. We think that there is some justification for an uplift to take account of the uncertain effects of quantitative easing and the CPI/RPI gap discussed above. However, we see little justification for the upper end of the range of the RFR above 1.5 per cent.

13.122 We provisionally adopt a range of 1 to 1.5 per cent for the real RFR. We note that the lower end of this range is well above current short-term real interest rates (which are negative) and would remain above short-term real interest rates during the period even if short-term real interest rates increased above the levels implied by current forward rates.

Equity market return and risk premium

13.123 The expected market return is the return that investors require for investing in equities. The ERP $(r_m - r_f)$ is the part of this return that compensates them for the additional risk associated with investing in equities, rather than in risk-free assets.

The UR

13.124 The UR said that a fall in the RFR would have led to a fall in returns on equity.[27]

NIE

13.125 NIE supported an ERP of 5.25 per cent, based on Ofgem precedent. It accepted that a figure of 5.0 per cent as used by the UR in its proposals could also be supported.

Previous CC inquiries

13.126 In the Stansted regulatory report, the CC derived an ERP of 3 to 5 per cent by subtracting its RFR of 2 per cent from a market return of 5 to 7 per cent. The CC effectively took a figure from near the top of this range because it considered that the consequences of setting too low a figure for the cost of capital (lack of investment) were worse than the consequences of setting too high a figure (higher charges). The implied figure for the market return would be 6.6 per cent and for the ERP 4.6 per cent.[28]

13.127 In the earlier Heathrow and Gatwick regulatory report, the CC similarly assumed a market return of 5 to 7 per cent (with an RFR of 2.5 per cent and ERP of 2.5 to 4.5 per cent). The CC also effectively took a figure from near the top of the range.[29]

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[27] UR Statement of Case, UR-7, paragraph 16.
[28] Because the chosen WACC (7.1 per cent) was 81 per cent of the way up the range for the WACC.
[29] CC, 2007, *BAA Ltd*, paragraphs 4.75–4.79 & 4.108.

13.128 In its Bristol Water report, the CC said that the market return was 5 to 7 per cent and the implied range for the ERP was 4 to 5 per cent. We said that historical average realized returns on equities for short holding periods supported the upper end of the range[30] but noted that current expected returns may be lower than the average expected historical returns. The lower end of the range was consistent with some forward-looking estimates based on combining observed dividend rates with forecast rates of dividend growth.

Summary of evidence

13.129 There are two main approaches to estimating the market return and the ERP: historical data reflecting actual returns over time; and forward-looking data relating to investors' current expectations of returns. We start by considering historical data.

Historical approach

13.130 The motivation for the historical approach is that expected returns remain constant over time and hence that average realized returns reflect the expected return.

13.131 The simplest approach is to calculate the arithmetic average of historical returns. It is appropriate to take an average of annual returns if there is a constant underlying return and the return in each year is independent of that in other years (see Appendix 13.3). Since annual returns have been highly variable, this approach requires looking at a long run of historical data. The DMS data set now contains 113 years of data from 1900 to 2012. Table 13.6 below shows arithmetic estimates for mean annual real returns on equities, bonds and bills for the period 1900 to 2012, together with statistics for the standard error and standard deviation of the estimates.

[30] Bristol Water, Appendix N, paragraph 93.

TABLE 13.6 **Returns on UK asset classes, 1900 to 2012**

	Mean returns % PA		
	AM	*SE*	*SD*
Real returns			
Equities	7.1	1.9	19.8
Bonds	2.4	1.3	13.7
Bills	1.1	0.6	6.3

Source: Credit Suisse Global Investment Returns Sourcebook 2013.

13.132 Table 13.7 shows average returns over the period from 1900 to 2012 for different holding periods. It is usual to quote figures for the average of one-year returns but investors in the equity market usually expect to invest in the market for longer than a year. We therefore show average returns for some longer holding periods as well, using a number of different estimators.

TABLE 13.7 **Real returns, 1900 to 2012**

per cent

	Return on equity				*ERP‡*			
	*Simple**	*Overlapping†*	*Blume§*	*JKM§*	*Simple**	*Overlapping†*	*Blume§*	*JKM§*
UK market, DMS data								
1-year holding period	7.1	7.1	7.1	7.0	6.0	6.0	6.0	5.9
2-year holding period	7.5	7.0	7.1	7.0	6.2	5.8	6.0	5.9
5-year holding period	6.7	6.8	7.0	6.8	5.2	5.3	5.9	5.7
10-year holding period¶	6.4	6.8	6.9	6.6	5.1	5.3	5.8	5.5
20-year holding period	6.7	6.9	6.8	6.1	5.7	5.6	5.7	5.1
UK market, Barclays data								
1-year holding period	6.9	6.9	6.9	6.8	5.8	5.8	5.8	5.8
2-year holding period	7.2	6.7	6.8	6.8	6.0	5.5	5.8	5.7
5-year holding period	6.2	6.4	6.8	6.6	4.8	5.0	5.7	5.6
10-year holding period¶	6.0	6.4	6.7	6.3	4.7	4.9	5.7	5.3
20-year holding period	5.9	6.4	6.5	5.8	5.1	5.1	5.5	4.9

Source: CC calculations based on *Credit Suisse Global Investment Sourcebook 2010*, written by Dimson, Marsh and Staunton (DMS) and Barclays Equity Gilt Study.

*The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110\text{-}h))^{1/h}$ where h is holding period, R_t is value of returns index at the end of year t and the expression is summed for (110/h) values of t for which non-overlapping data is available. Years are dropped at the beginning of the data period if the holding period is not a multiple of the total data period.
†The mean is calculated from the formula $(\sum(R_{t+h}/R_t)/(110\text{-}h))^{1/h}$ where h is holding period, R_t is value of returns index at the end of year t and the expression is summed for (110–h+1) values of t for which overlapping data is available.
‡ ERP is calculated relative to UK Treasury bills.
§The Blume unbiased estimator is a weighted average of arithmetic and geometric mean and the JKM (Jacquier, Kane and Marcus) small sample efficient estimator is calculated from the estimated mean and variance of lognormal returns..
¶Average of 10- and 11-year holding periods.
Note: Returns for holding periods greater than one year are expressed as annual equivalent returns.

13.133 The data in Tables 13.6 and 13.7 suggests an average market return of around 6 to 7 per cent (for both world and UK markets). In order to calculate the historical ERP, it is necessary to subtract the historical RFR from the historical market return. Index-linked gilts have not been available for the full period and it is usual to use the return on Treasury Bills as a proxy for the RFR. However, it is doubtful that Treasury Bills have been free of inflation risk (for example, rates were negative from 1970 to 1979 when inflation was high). The data in Table 13.6 suggests an average ERP over Treasury Bills of about 5 to 6 per cent.[31] The standard error around these historical estimates is substantial, implying a 95 per cent confidence interval of around 3 to 11 per cent for the market return and around 3 to 9 per cent for the ERP.

13.134 An alternative procedure, suggested by Fama and French, is to estimate the underlying return from the sum of average dividend yield and the average rate of dividend growth.[32] Using the full run of historical data for the UK, this suggests an underlying expected market return of 5.5 per cent[33] and an ERP over Treasury Bills of 4.4 per cent (using Barclays data which prior to 1962 comprises fewer companies than DMS but shows broadly similar (albeit slightly lower) results for average returns).

13.135 Fama and French's work for the USA provided evidence of a fall in expected returns over time, with expected returns being lower since 1950 than before 1950. Many other papers have reported similar findings, though the issue remains controversial.[34] The statistical evidence for the UK is less extensive[35] but, as illustrated in Figure 13.5, the current dividend yield (about 3.6 per cent) is below the historical average (4.5 per cent). Unless future dividend growth is higher than in the past, this would suggest that expected returns are about 1 per cent lower than the past average,

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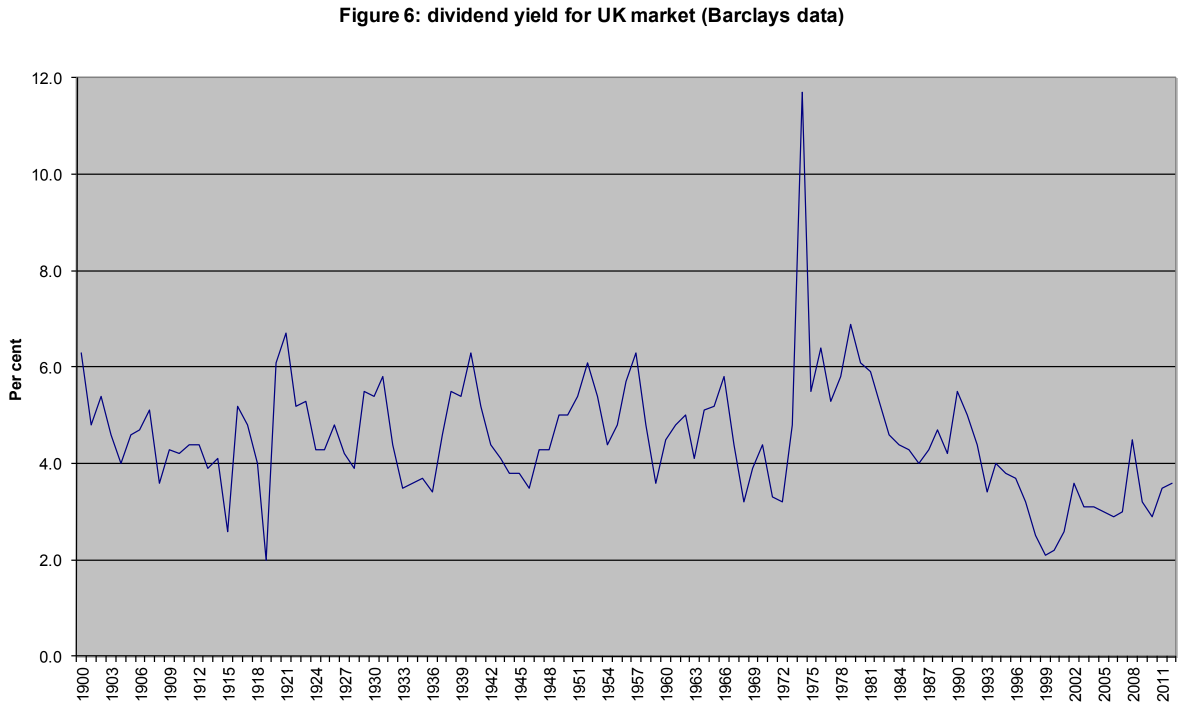
[31] ERPs are sometimes calculated relative to long-dated gilt yields, rather than Treasury Bills. As gilts are subject to additional risks compared with Treasury Bills (greater inflation risk and also price volatility risk), we have not shown ERPs relative to gilts.
[32] Fama, E F and French, K R, 'The Equity Premium', *Journal of Finance*, April 2002.
[33] This results from average dividend yield of 4.5 per cent and dividend growth of 1 per cent a year (Barclays data).
[34] Welch and Goyal, 'A comprehensive look at the empirical performance of equity premium prediction', *Review of Financial Studies*, 2008, which did not find robust evidence that forecasts of the ERP based on dividend yields were better at predicting future returns than the assumption of a constant ERP. The issue of the *Review of Financial Studies* in which this paper appeared included other papers suggesting that the evidence suggested the ERP was predictable , for example: Campbell, J and Thompson, S: 'Predicting Excess Stock Returns Out of Sample: Can Anything Beat the Historical Average?' and Cochrane, J: 'The Dog That Did Not Bark: A Defense of Return Predictability'.
[35] Two papers that did find evidence of a reduction in the expected market return or ERP for the UK (albeit at different times) are Buranavityawut, N, M C Freeman and N Freeman (2006), 'Has the equity premium been low for 40 years?', *North American Journal of Economics and Finance*, 17, pp191–205; and Vivian, A, 'The UK equity premium, 1901-2004', *Journal of Business and Financial Accounting*, 2007. The first paper suggests that the expected equity premium may have fallen in the 1960s in the UK and other countries, while the second paper suggests that there was a permanent decline in the UK market dividend-price ratio during the early 1990s.

implying a market return of about 4.5 per cent and an ERP over Treasury Bills of 3.4 per cent (using Barclays data).[36]

FIGURE 13.5

Dividend yield for UK market (Barclays data)



Source: Barclays Equity Gilt Study 2013.

Forward-looking approaches

13.136 Noting that dividend yields are lower than in the past, DMS inferred that, for the world index, a forward-looking risk premium (over Treasury Bills) would be 4.5 to 5 per cent.[37] Given a difference of 1 per cent between average return on bills and ERP (see Table 13.3), this implies an expected return of 5.5 to 6 per cent.[38]

13.137 A commonly used approach is to project dividends using analysts' forecasts (which extend out by four or five years) and a longer-term dividend growth rate. The expected return is then the discount rate at which the present value of future divi-

[36] These figures do not take into account payments to shareholders other than dividends, for example share repurchases.
[37] *Credit Suisse Global Investment Sourcebook 2013.*
[38] *Credit Suisse Global Investment Sourcebook 2010 and 2013*, section 2.6.

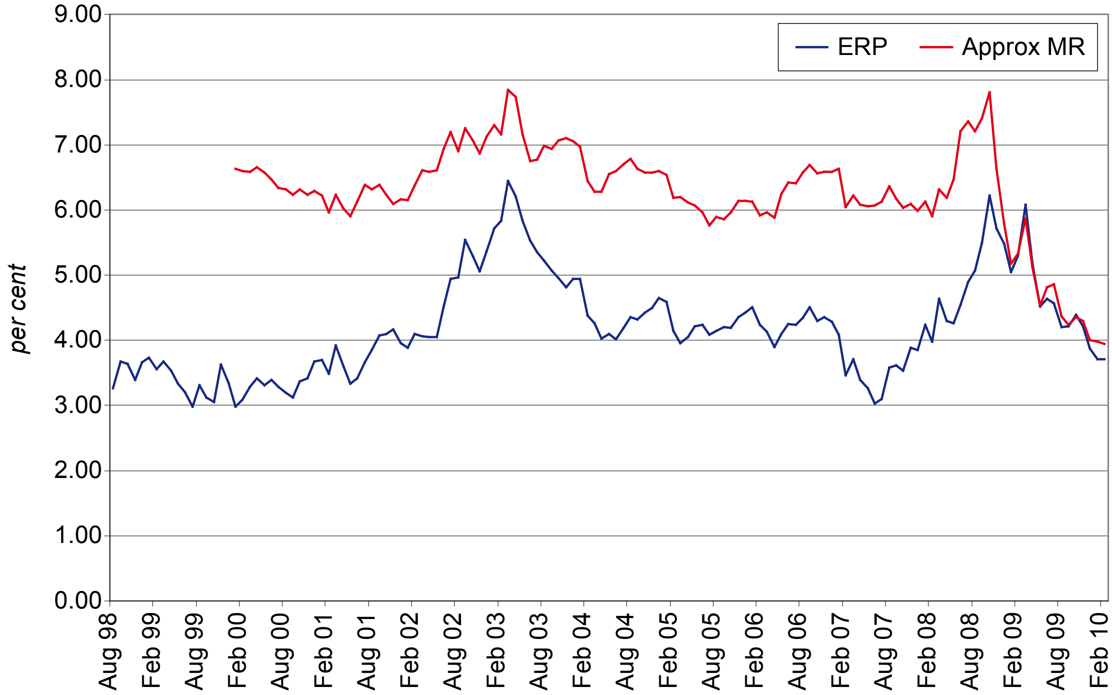
dends is equal to the current market price. A limitation of this approach is that it is necessary to make an assumption about future long-term growth of dividends (which has a major effect on the calculation since dividends beyond year 4 or 5 account for a large part of present value at plausible discount rates).

13.138 Figure 13.6 shows estimates of ERP using this methodology published in an article in 2010 in the *Bank of England Quarterly Bulletin*. These estimates are based on the assumption that the future long-term growth in dividends per share is equal to an estimate of the potential growth of the economy—however, the authors of the article note that this choice of future long-term growth rate is essentially arbitrary.[39] The estimates in Figure 13.6 suggest that the expected ERP has fluctuated around 4.5 per cent. We have attempted to calculate the expected market return implied by these estimates of the ERP: this appears to have fluctuated around 6.5 per cent, but since the credit crunch declined markedly (up to February 2010).

[39] Mika Inkinen, Marco Stringa and Kyriaki Voutsinou: 'Interpreting equity price movements since the start of the financial crisis', *Bank of England Quarterly Bulletin*, 2010 Q1.

FIGURE 13.6

Estimated ERP and approximate implied real market return



Source: Mika Inkinen, Marco Stringa and Kyriaki Voutsinou: 'Interpreting equity price movements since the start of the financial crisis', *Bank of England Quarterly Bulletin*, 2010 Q1.

13.139 We agree with the authors of the *Bank of England Quarterly Bulletin* article that it is essentially arbitrary to assume future long-run growth in dividends per share equal to potential economic growth. Indeed, we see empirical support for expecting long-run growth in dividends per share to be less than potential economic growth. The historical growth rate in real dividends for the UK from the Credit Suisse/DMS data is only 0.5 per cent[40] and around zero using the Barclays data[41]—this is significantly less than real UK economic growth over the same period (1900 to 2010) of 1.89 per cent.[42] It is also the case that growth in dividends per share has been significantly less than economic growth in more recent periods. Since 1950, growth in dividends per share has been 1.1 per cent, compared with 2.4 per cent for GDP growth, while

[40] *Credit Suisse Global Investment Returns Sourcebook 2013*, Table 11.
[41] For the Barclays data, we calculated a trend growth rate in real dividends over 1900 to 2009 of 0.2 per cent from a regression of real dividends on time (the Barclays data showed a very sharp decline in real dividends up to 1915 and the geometric mean growth in dividends for 1900 to 2009 was –0.2 per cent).
[42] Lawrence H Officer and Samuel H Williamson, 'Annualized Growth Rate and Graphs of Various Historical Economic Series', MeasuringWorth.Com. See: www.measuringworth.com/growth/.

since 1980, growth in dividends per share has been 1.6 per cent, compared with 2.3 per cent for GDP growth.[43]

13.140 Bearing in mind these points and also that analysts' forecasts may be subject to upward bias,[44] we regard the approximate 6.5 per cent market return suggested by Figure 13.6 as an upper estimate.

13.141 Another possible source for forward-looking estimates of the market return is surveys of investors, market participants and academics. However, the results of such surveys tend to depend on the identity of the respondents. In this report we have preferred to consider the underlying data on which survey respondents presumably base their views.

CC discussion

13.142 We noted above that returns for index-linked gilts were not available for the full historical period and the Treasury Bill rate may not be a true RFR. This means that it is not valid to add ERPs based on Treasury Bills to our RFR based on underlying longer-dated index-linked gilt yields. We therefore prefer to derive the ERP by subtracting the RFR from the expected market return. A further reason for using this approach with historical data is that, historically, the market return has tended to be less volatile than the ERP (as measured, for example, by the ratio of standard deviation to mean) and there is some evidence of the ERP being negatively correlated with Treasury Bill rates.

13.143 With the forward-looking approach, a forward-looking RFR is relevant and hence by assumption is the same as the RFR in the cost of capital. Consistency between the

[43] These figures are calculated using the Barclays dividends data and ONS data for GDP.
[44] A large body of literature suggests that there may be a tendency for analysts' forecasts to overreact to changes and on average to be too optimistic, for example W F M DeBondt and R H Thaler (1990), 'Do Security Analysts Overreact?', *American Economic Review* 80, pp52–57.

two is ensured by calculating the ERP by subtracting the RFR from the expected market return, as suggested in the previous paragraph.

13.144 The interpretation of the evidence on market returns remains subject to considerable uncertainty. The CC has 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 forward-looking estimates which tend to support an upper limit of 6.5 per cent. We note the following points in support of setting an upper limit for the market return of 6.5 per cent:

(a) We consider that the return on the market is a more stable parameter than the ERP. However, it remains the case that it exhibits considerable volatility and cannot therefore be regarded as fixed over time.

(b) We consider that there is logic to the proposition that a long-term decline in RFRs, as we discuss above, should correspond with an increased demand for equities and thus increased prices and lower returns.

(c) We note research conducted by DMS suggesting a clear relationship between real interest rates and real returns on equities and bonds in the subsequent five-year period.[45]

(d) A forward-looking expectation of a return on the market of 7 per cent does not appear credible to us, given economic conditions observed since the credit crunch and lowered expectations of returns.

13.145 Further, the implied range for the ERP of 4 to 5 per cent[46] appears consistent with the following evidence:

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[45] *Credit Suisse Global Investment Returns Yearbook 2013*, Figure 5.
[46] We associate the lower market return (5 per cent) with the lower RFR (1 per cent) and the higher market return (6.5 per cent) with the higher RFR (1.5 per cent).

(a) the lower end of the 5 to 6 per cent range suggested by the pure historical analysis conducted by DMS (see paragraph 13.133);

(b) DMS's decomposition approach (see paragraph 13.136) suggesting an ERP of 4.5 to 5 per cent; and

(c) Fama & French's forward-looking projections based on the DGM suggesting an ERP of 4.4 per cent (see paragraph 13.134).

13.146 Based on the above, we consider that the appropriate upper limit for the market return is 6.5 per cent. In the context of setting a cost of capital for NIE, we are less concerned with a lower limit to the expected market return (since we would wish to avoid NIE's cost of capital being too low), but in this context we consider 5 per cent an appropriate lower bound figure.[47]

13.147 We therefore provisionally estimate a range of 5 to 6.5 per cent for the market return, and implied range of 4 to 5 per cent for the ERP.

Beta

13.148 Beta is a factor in the CAPM reflecting the risk of a particular asset or portfolio of assets relative to the market as a whole.

13.149 Within a CAPM framework, changes in gearing affect equity betas. Hence, it is necessary to adjust for gearing differences in order to make comparisons between equity betas (for example, by calculating the asset beta, ie the beta at zero gearing). Our analysis takes this into account.

[47] Figures lower than 5 per cent may well be appropriate in other contexts, for example providing advice to equity investors on the lower end of the range of expected returns before costs. In this context, we note that the Financial Services Authority (FSA) requires UK financial advisers to project nominal returns on a notional product two-thirds invested in equities and one-third in fixed income (before costs and personal tax) using rates of 5, 7 and 9 per cent. From 2014 onwards the FSA has reduced the assumed returns to 2, 5 and 7 per cent. Assuming RPI of 2.9 per cent, this implies real returns of –0.9, 2.1 and 4.1 per cent.

The UR

13.150 First Economics (for NIE) produced Table 13.8 showing asset betas for comparator utilities.

TABLE 13.8 **Ranges for utility asset beta based on recent data (figures at the end February 2011)**

	Low	*Average*	*High*
Spot estimate	0.22	0.27	0.32
Average over last year	0.26	0.32	0.43
Annual averages over last 5 years	0.26	0.39	0.63
Annual averages over last decade	0.08	0.31	0.63

Source: First Economics based on data from Thomson DataStream data, and assuming a debt beta of 0.1.

Note: Sample includes: National Grid, Anglian, Pennon, Kelda, Northumbrian, Severn Trent, United Utilities, Viridian, ScottishPower and Scottish and Southern Energy. Of these, six remain listed and are in the sample over the last year.

13.151 First Economics performed a comparative analysis of the systematic risk of NIE with GB electricity distribution and transmission companies, based on the following factors:[48]

(a) exposure to demand risk: revenue cap vs price cap;

(b) exposure to cost risk; and

(c) operational gearing: average industry RAB to revenue ratio.

13.152 Based on the comparative analysis, First Economics concluded that it was difficult to distinguish NIE from the conventional network businesses in GB and particularly from GB electricity distribution companies, pre-RIIO. First Economics noted that Northern Ireland and GB electricity networks' operational gearing was comparable and that they faced similar demand risks through the operation of a revenue cap. First Economics concluded that NIE exhibited the same sort of risk profile as a conventional GB-regulated network operating under a five-year RPI–X price control, and that, all things being equal, they should therefore have the same beta.[49]

[48] First Economics, 'An estimate of NIE T&D's cost of capital', December 2011, p5.
[49] ibid, p9.

13.153 First Economics recommended a range of 0.34 to 0.44 but noted that it had a preference for the upper end of this range on the grounds that the implied cost of equity when using the lower end of the range felt implausible. It recommended that the UR should choose a point estimate for the asset beta of between 0.4 and 0.425.[50]

13.154 The UR noted that statistical measures of beta reported by Ofgem for National Grid, SSE plc, and for the three listed WaSCs, appeared to have fallen in recent years and were now lower than the previous equity beta estimates on which the UR's RP5 asset beta assumption of 0.42[51] was based. The UR said that this implied that investors had come to appreciate better the low-risk nature of regulated utilities.

13.155 The UR told us that its proposals for the structure of the price control would reduce systematic risk for NIE T&D in such a way as to warrant a further reduction in assumed beta.

NIE

13.156 NIE told us that there had recently been abnormally high volatility in equity markets, so that measured betas for utility companies were temporarily depressed and did not reflect accurately the underlying business risk faced by the companies. On that basis, a long-term perspective was more appropriate.[52]

13.157 NIE suggested that the approach taken to determine the beta, RFR and ERP should use a long-term time horizon, and told us that the CC had recognized this principle in past determinations.[53]

[50] ibid, p10.
[51] Based on a debt beta of 0.1
[52] NIE supplementary submission, p146, paragraph 4.6.
[53] ibid, paragraph 4.8.

13.158 NIE's proposed figure for equity beta was based on a notional debt beta of 0.1 and a notional asset beta of 0.42. Asset beta is defined as the weighted average of equity beta and debt beta, using notional gearing as the weight for the debt beta. These figures were proposed by the UR in its draft proposals for RP5 and adopted by NIE.[54]

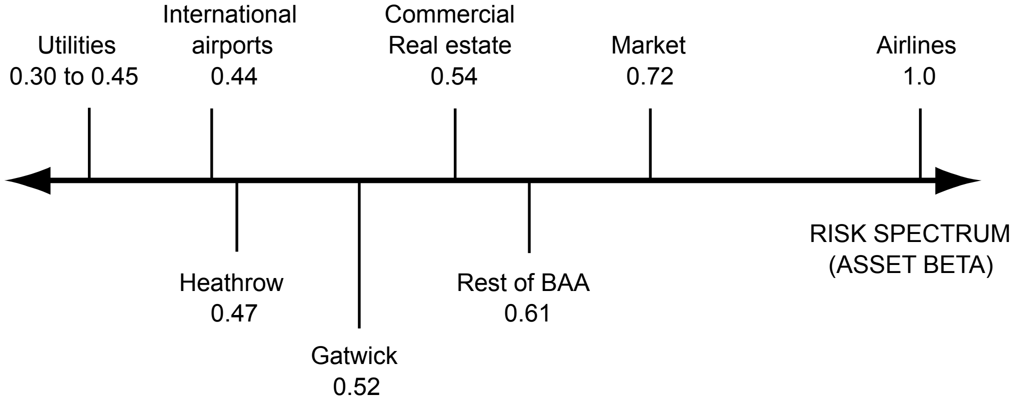
Previous CC inquiries

13.159 The most recent price-cap-setting inquiry was Bristol Water. In that inquiry, the CC derived asset betas from an analysis of daily total return data for listed WaSCs. It then added 18 per cent on to these figures to allow for Bristol Water's higher operational gearing.[55] The implied asset beta range was 0.32 to 0.43.[56]

13.160 Airports are likely to have different risk characteristics from water companies. However, the Heathrow and Gatwick airports inquiry included a comparison of asset betas, shown in Figure 13.7 below. Utilities are positioned at the lower end of the spectrum at between 0.3 and 0.45.

FIGURE 13.7

Risk spectrum (asset beta)



Source: CC analysis in Heathrow and Gatwick regulatory report (2007).

[54] NIE Statement of Case, Chapter 15, paragraph 3.20.
[55] Bristol Water (2010), Appendix N, paragraph 137.
[56] Assuming a debt beta of 0.1. Ibid, Table 11.

CC estimates of beta

13.161 As already noted, equity beta depends on gearing, but even after adjusting to a similar gearing basis, a company's estimated beta can vary for a number of reasons, including:

(a) Differences in the estimation period and in the frequency of returns data used for estimation. Daily, weekly or monthly data may be used. Daily data may be preferred as it is likely to have the smallest standard errors and may be regarded as more statistically robust (providing the share's trading frequency is sufficient) but monthly betas may be preferred as they tend to be more stable and therefore more reliable for use in the context of a regulatory determination where prices are set over a five-year period.

(b) Whether the data is adjusted for any tendency of true betas to converge to be closer to the market value of one than are estimated betas. Blume adjustments[57] or Bayesian adjustments are two such adjustment mechanisms. We have not seen the merits of such adjustments in the context of regulated utilities whose underlying risk profile may be expected to be stable and whose beta may be expected to be below 1.

(c) The assumption made about debt beta in adjusting for gearing. In this case we have assumed an debt beta of 0.1.

13.162 Appendix 13.4 sets out our estimates of equity and asset beta for comparator UK utilities using daily data. Using a series of two-year windows beginning between April 2000 and September 2011, we estimate a rolling asset beta for a utility portfolio of 0.35 assuming a debt beta of 0.1. We estimate a 95 per cent confidence interval around this estimate of 0.26 to 0.47. We also estimate asset betas using a series of five-year windows using monthly data. The summary statistics are show in Table 13.9.

[57] The Blume-adjusted beta is a weighted average of raw beta and 1, where the weight on the raw beta is 0.67.

TABLE 8 **Asset betas**

	Two years, daily data			*Five years, monthly data*		
	Mean	*95% interval**		*Mean*	*95% interval**	
SSE	0.45	0.27	0.62	0.43	0.20	0.70
National Grid	0.34	0.26	0.44	0.48	0.33	0.69
United Utilities	0.33	0.23	0.48	0.37	0.28	0.51
Severn Trent	0.31	0.12	0.45	0.34	0.20	0.46
Pennon	0.27	0.05	0.48	0.27	0.08	0.48
Portfolio	0.35	0.26	0.47	0.42	0.33	0.58

Source: CC calculations based on Bloomberg data.

*Over the period, 95 per cent of the observations fell within this range.

13.163 We note the following:

(a) We consider that estimates based on daily data may be preferred for frequently-traded shares as they are more statistically robust. However, monthly betas may be more suitable for estimation of beta using less well-traded shares.

(b) We do not consider that the evidence suggests that utility companies' betas converge to one (nor would one necessarily expect this for regulated companies); hence we do not consider that raw betas estimated from daily data should be subject to Blume or Bayesian adjustment.

(c) We have adopted a debt beta assumption of 0.1 (the debt beta assumption makes little difference to estimated cost of capital as long as the gearing in the WACC is not too different from the gearing of the WaSCs for which equity beta was estimated).

13.164 With regard to the period for estimating beta we consider:

(a) The longer period data indicates that utility company betas do not tend to converge to 1. Hence, we see no justification for applying the Blume adjustment (which assumes betas do converge to 1) to utility company betas. As regards a Bayesian or Vasicek adjustment, we accept that such an adjustment could be appropriate if we were estimating the beta for a quoted company (as such an adjustment would combine information on that specific company's beta with information on other companies' betas). However, this is not what we are doing.

We are estimating a beta for a portfolio of utility companies to apply to an unquoted utility company (NIE) and, in such circumstances, we see no role for a Bayesian or Vasicek adjustment.

13.165 With regard to the calculation of gearing for estimating the asset beta, we have used net debt in our calculations, that is long-term debt net of cash balances. We note that this may give lower measures of gearing than if long-term debt is used with no adjustment for cash balances. We regard either method as justifiable, although for certain companies one approach or the other may be more appropriate depending on the requirement for working capital.

CC discussion

13.166 Measured asset betas for GB utility companies are low, reflecting the relatively low risk of the underlying regulated business—this also means that utility companies tend to be regarded as 'defensive' investments.

13.167 Historical observations of beta measure companies' historic systematic risk profiles. We considered whether there could be a case for suggesting that NIE's beta will be lower or higher than in the past. We concluded that there was no strong case for thinking beta would be different than in the past and consequently that we could estimate beta from historical data.

13.168 The comparators that we have used to estimate beta relate to GB regulated utilities. These are regulated by Ofgem under a regulatory framework that has been established for a long period of time and is well understood by investors. We think the regulatory framework applying to NIE is similar to that of Ofgem in many respects, particularly to that applying pre-RIIO, and we note the findings of First Economics in this respect (see paragraph 13.152). However, we consider that the Northern Ireland regime may be less well understood by investors. For these reasons, investors may perceive the systematic risk of NIE to be towards the upper end of the GB comparator set.

13.169 We note that there is significant volatility in our own, and First Economics', beta estimates. Whilst taking averages over the recent past or the longer term suggests an average asset beta for our portfolio of below 0.4, there is significant uncertainty associated with such estimates. We note that the 95 per cent confidence interval around the two-year daily data asset beta for our GB portfolio over the last two years is 0.26 to 0.47. The 95 per cent confidence interval around the five-year monthly beta for the portfolio is slightly higher at 0.33 to 0.53 (see Appendix 13.4).

13.170 Noting the confidence intervals for beta based on two-year daily data and five-year monthly data span a range of 0.26 to 0.55; the possibility that these betas do not accurately reflect investor perceptions of systematic risk of NIE; and the evidence from previous CC inquiries (see paragraphs 13.159 and 13.160); our provisional estimate for NIE's asset beta is a range of 0.4 to 0.45 assuming a debt beta of 0.1.

Estimated cost of capital

13.171 The main points of our thinking on the cost of capital are:

(a) We consider that the gearing assumed in the WACC should be consistent with the gearing used to assess financial ratios and calculate tax.

(b) The assumed level of gearing should generate financial ratios consistent with the company maintaining investment grade status—on a cautious basis, we have chosen to apply NIE's existing 50 per cent gearing in order that our projections are consistent with NIE maintaining investment grade status.

(c) Our estimate of NIE's existing cost of debt is 3.6 per cent and of its new debt is 2.7 per cent, giving an overall average cost of debt of 3.4 per cent.

(d) As regards the cost of equity:

(i) Current index-linked yields are about 0.5 per cent—as they may still be affected by market distortions we consider that a range of 1 to 1.5 per cent for the RFR is appropriate.

(ii) A reasonable range for the market return is 5 to 6.5 per cent, implying an ERP of 4 to 5 per cent.

(iii) We estimate GB utility company asset betas to be in the range 0.35 to 0.45. We accept that these are not like-for-like comparators, hence we estimate NIE's asset beta towards the upper end of the range at between 0.4 to 0.45 and hence its equity beta (at 50 per cent gearing and assuming a debt beta of 0.1) to be 0.7 to 0.8.

13.172 Based on these assumptions, we calculate a range for NIE's WACC of 3.6 to 4.5 per cent—see Table 13.10.[58]

TABLE 13.10 **Calculated WACC range for NIE**

	CC low	*CC high*
Gearing (%)	50	50
Cost of debt (pre-tax) (%)	3.4	3.4
Cost of equity (post-tax) (%)	3.8	5.5
WACC (%)	3.6	4.5
Cost of equity calculation		
RFR (%)	1	1.5
ERP (%)	4	5
Equity beta	0.7	0.8
Cost of equity (post-tax) (%)	3.8	5.5
Asset beta calculations		
Debt beta assumption	0.1	0.1
Asset beta	0.4	0.45
Gearing (%)	0.5	0.5

Source: CC calculations.

13.173 Our calculated range for the (post-tax) cost of equity at 50 per cent gearing of 3.8 to 5.5 per cent for NIE compares to our estimated (pre-tax) cost of new debt of 2.7 per cent in total (and 2.4 per cent before fees and cash costs).

[58] With a debt beta of zero, some of the individual numbers are changed but the range remains the same.

13.174 We consider it unlikely that the cost of capital lies at the very top or very bottom of the estimated range as this would involve the lower or upper estimates for each parameter all coinciding.

13.175 In addition, we consider that the lower bound of 5 per cent for the expected return on the market is less well supported than the upper end of the range of 6.5 per cent. Estimates below 5.5 per cent rely on the assumption that forward-looking expectations of market returns are lower than in the past. Whilst there is some support for this assumption in the literature (as noted in paragraph 13.135), it remains controversial, and there is limited UK-specific research in this area. We consider that the weight of evidence tends to support numbers between 5.5 and 6.5 per cent for the expected market return. Whilst we have decided to retain 5 per cent as a possibility, we are less confident with this estimate and, as a corollary, with numbers at the lower end of the WACC range.

13.176 Our provisional view is that the plausible range for NIE's WACC is between 3.9 and 4.3 per cent. Hereinafter we refer to this as 'the range'. We have adopted the mid-point of this range, 4.1 per cent, as the WACC for RP5.

13.177 Our cost of capital range is lower than that of the UR and that of NIE—see Table 13.11:

(a) Our cost of capital is different from the UR's mainly because we have estimated a lower cost of equity of 4.4 to 5.2 per cent (the UR estimated 5.7 per cent). Our cost of debt is the same as its estimate. The combined effect is that our WACC range of 3.9 to 4.3 per cent and our point estimate of 4.1 per cent are lower than the UR's point estimate of 4.6 per cent.

(b) Our cost of capital is below NIE's estimate because we have estimated a lower cost of equity. We have not allowed a Northern-Ireland-specific premium on the cost of equity and we have lower estimates for the RFR and ERP.

TABLE 13.11 **Cost of capital for NIE**

	CC plausible range	*CC point estimate*	*UR original*	*NIE regeared**
Gearing (%)	50		50	50.0
Cost of debt (pre-tax) (%)	3.4		3.4	3.6
Cost of equity (post-tax) (%)	4.4–5.2		5.7	6.9
WACC (vanilla WACC) (%)	3.9–4.3	4.1	4.55	5.2
Cost of equity calculation				
RFR (%)	1.0–1.5		2	2
ERP (%)	4.0–5.0		5	5.25
Equity beta	0.70–0.8		0.74	0.74
Asset beta	0.40–0.45		0.42	0.42
NIE premium	0		0	1
Cost of equity (post-tax) (%)	4.4–5.2		5.7	6.89

Source: CC calculations.

*Adjusted to 50 per cent gearing using 0.1 debt beta.

Comparison with previous regulatory decisions

13.178 We consider that consistency with previous decisions is relevant and any significant changes should be satisfactorily explained and well justified.

13.179 Table 13.12 shows a comparison with the WACCs recommended in the CC's most recent regulatory reports on Heathrow and Gatwick (2007) and Stansted airports (2008) and Bristol Water (2010). Our cost of debt for NIE is slightly lower than the CC's recommended cost of debt for the airports, reflecting more recent credit market conditions. Our cost of equity for NIE is towards the lower end of the range of the CC's recommended cost of equity for the airports, reflecting the lower risk that utility companies face compared with airports. Our cost of equity sits in the middle of the range proposed for Bristol Water. As discussed earlier in this section, the range for the assumed market return of 5 to 6.5 per cent is narrower than the range the CC assumed in the airports and Bristol Water inquiries of 5 to 7 per cent. We also assume a lower range for the RFR of 1 to 1.5 per cent.

TABLE 13.12 **Comparison of NIE WACC with recent CC reports**

	NIE	*Heathrow Oct 07*	*Gatwick Oct 07*	*Stansted Oct 08*	*Bristol Water June 10*
Gearing (%)	50	60	60	50	60
Cost of debt (pre-tax) (%)	3.4	3.6	3.6	3.4–3.7	3.9
Cost of equity (post-tax) (%)	4.4–5.2	4.8–7.7	5.0–8.4	5.0–8.2	3.6–6.6
WACC range* (%)	3.9–4.3	4.0–5.2	4.1–5.5	4.2–6.0†	3.8–5.0
WACC estimate* (%)	[4.1]	5.1	5.3	5.6†	5.0
Cost of equity calculation					
RFR (%)	1.0–1.5	2.5	2.5	2.0	1.0–2.0
ERP (%)	4.0–5.0	2.5–4.5	2.5–4.5	3.0–5.0	4.0–5.0
Market return (%)	5.0–6.5	5.0–7.0	5.0–7.0	5.0–7.0	5.0–7.0
Asset beta	0.40–0.45	0.42–0.52	0.46–0.58	0.55–0.67	0.32–0.43
Equity beta	0.7–0.8	0.90–1.15	1.00–1.30	1.00–1.24	0.64–0.92

Source: CC calculations.

*We have calculated vanilla WACC consistent with pre-tax WACCs shown in the CC airports reports.

13.180 We compared our estimated WACC for NIE with recent findings of sectoral regulators (see Table 13.13). In order to facilitate the comparison, we have adjusted the CC cost of capital to a comparative level of gearing. Our WACC range, converted to a gearing of 65 per cent, comparable with recent Ofgem decisions, is 4.2 to 4.5 per cent which is within the range used by Ofgem in recent decisions (4.2 to 4.7 per cent).

13.181 The basis of our estimates of WACC has been set out fully in detail in this section, and consequently provides a full explanation of any differences from estimates of the cost of capital used by sectoral regulators.

TABLE 13.13 **Comparison of CC estimates of NIE's WACC with recent Ofgem decisions**

	CC NIE point estimate Aug 13	*CC NIE plausible range (regeared)* Aug 13*	*RIIO–GD1 2013–2021*	*National Grid gas transmission 2013–2021*	*National Grid electricity transmission 2013–2021*	*Ofgem DPCR5 Dec 09*
Gearing (%)	50	65	65	62.5	60	65
Cost of debt (pre-tax) (%)	3.4	3.5	2.92†	2.92†	2.92†	3.6
Cost of equity (post-tax) (%)‡	4.8	5.7–6.6	6.7	6.8	7	6.7
WACC (%)	4.1	4.2–4.5	4.2	4.4	4.55	4.7
Cost of equity calculation		Illustrative figures‡				
RFR (%)		1.1–1.4‡	2	2	2	NA§
ERP (%)		4.5–5.0‡	5.25	5.25	5.25	NA§
Equity beta		1.01–1.04‡	0.9	0.91	0.95	NA§
Asset beta		0.42–0.43‡	NA§	NA§	NA§	NA§
Cost of equity (post-tax) (%)		5.7–6.6	6.7	6.8	7	6.7

Source: CC calculations.

*Different gearing level assumed for purpose of comparison. It is assumed that the change in gearing does not affect the cost of debt but does affect equity beta via the Miller formula.
†iBoxx ten-year simple trailing average index for 2013/14—the value of the index may change during the price control period, and any changes will be reflected in the WACC.
‡Illustrative figures, consistent with the plausible range for the WACC, used for the purposes of the regearing calculation.
§Unclear from decision.

14. Unresolved RP4 issues

Introduction

14.1 In its Statement of Case,[1] NIE drew our attention to three outstanding issues with respect to the RP4 period:

(a) the UR's failure to approve RP4 capex efficiency incentive payments, with a total value of £4.2 million;

(b) costs incurred by NIE in RP4 which have not been approved in relation to the Enduring Solution IT project, with a value of £1.3 million; and

(c) an outstanding question regarding the interpretation of the capital allowances term in the RP4 price control with a value of £0.9 million.

14.2 NIE said that because these issues remained unresolved, it had consequently under-recovered relative to its full RP4 revenue entitlement. NIE therefore argued that these issues should be fairly and definitively resolved as part of the RP5 price control process. It said that the amounts in question should therefore be taken into account when setting the correction factor (K_t) to be applied.[2]

14.3 The UR, in its response to NIE's submission, stated that all three of the issues raised were matters relating to RP4. It argued that issues were either outstanding points relating to the implementation of RP4 (including the interpretation of some aspects of the licence), or related to decisions that the UR had already taken. It therefore said that the matters were not appropriate for us to review or that we would have no jurisdiction to do so.[3]

14.4 In the following subsections, we review the details of the points raised by the UR and consider whether these are issues that fall within our terms of reference. While our

[1] NIE Statement of Case, Chapter 12.
[2] NIE Supplementary Submission, Annex 10, paragraph 2.4.
[3] UR Supplementary Submission, section 21.

role is to consider whether the price control conditions of RP4 operate against the public interest and, as necessary, determine price control conditions for RP5, previous determinations may arguably be relevant if they materially affect recoverable revenues going forward. For example, this could arise if a material error in relation to a previous control affected the RAB applicable to the RP5 period.

Unresolved issues

RP4 capex efficiency incentive payments

14.5 NIE said that the D_t term in the RP4 price control conditions[4] (see paragraph 3.21) provided a mechanism for NIE to recover additional regulated revenues in respect of: 'amounts arising under arrangements approved by the Authority which are designed to incentivise efficiency in network capital investments, and which shall be calculated in accordance with the 2006 Direction' (D_t term, subparagraph (iv)).[5]

14.6 In practice, NIE submits its claims for capital efficiency incentive allowances to the UR annually, basing its assessment of labour productivity on capex outputs relating to certain selected activities repeated from year to year (and which have been used consistently throughout RP4). NIE said that the UR approved NIE's assessments for 2007/08 and 2008/09, but had not yet approved its claims for subsequent years. It had also applied for approval of further capex efficiency incentive payments attributable to relevant capex efficiency gains for the RP4 extension period (nine months to 31 December 2012). It said that the UR was now questioning whether it was appropriate to use the methods applied in previous years to measure NIE's efficiency in respect of procurement and manpower costs. While the UR had now appointed consultants (BDO) to audit both the productivity element and the procurement element of the claims, it noted that there was substantial delay in resolving the claims. It also

[4] Provided for in Annex 2, paragraph 2.3.
[5] NIE Statement of Case, Chapter 12, paragraph 2.1.

said that it was not appropriate for the UR to change the basis of operation of the incentive mechanism during RP4, without formally amending the 2006 Direction in accordance with its terms. [6]

14.7 The UR agreed that the issue remained outstanding. It said that it was questioning the accuracy and completeness of the method used in previous years and the data that underlay it.

14.8 It said, in summary, that the mechanism provided for NIE to retain 38.9 per cent of the efficiency savings that it achieved in two categories: *(a)* procurement efficiencies, and *(b)* labour productivity efficiencies. In respect of procurement, the efficiencies were to be measured by the difference between actual procurement costs and the costs that would have been incurred under the corresponding procurement contract in 2006/07 (the last year of RP3), after adjusting for inflation. In respect of labour productivity, the efficiency was to be measured by reference to the variation in man-power used for a particular capex project in a year in RP4, and the amount of man-power that would have been used for the same work in 2006/07. The 2006 Direction did not, however, specify the output measures that were to be used for the purposes of calculating labour productivity.

14.9 The UR said that it had undertaken detailed examination for the claims after 2008/09 because the value of the claimed efficiencies had been much more substantial than the previous years (£590,000, £1.1 million and £1.78 million respectively). It stated that it had commissioned an audit of these claims.[7] It said that the BDO audit provided grounds for several concerns about the efficiency submissions that NIE had made in relation to these three years. It noted that some of these concerns related to what appeared to be calculation errors or inappropriate calculation methodologies

[6] ibid, Chapter 12, section 2.
[7] UR Supplementary Submission, paragraph 21.

used by NIE, and also it was concerned that NIE might have been selective in the activities that it had measured to calculate its efficiencies.

14.10 The UR said that in any event this was an RP4 issue that should be dealt with by the regulator in the usual way.[8] It stated that no special circumstances applied in this case (it drew a contrast to the capitalization issues (see paragraphs 15.16 to 15.23), where it argued that there was a special circumstance in regard to what it characterized as customers paying twice for the same activities). It said that it was waiting for us to confirm whether it agreed that this was not an issue for our redetermination before it reached a conclusion on this issue.

Unapproved costs in relation to the Enduring Solution IT project

14.11 NIE said that the D_t term of the RP4 price control provided that NIE should be entitled to recover additional regulated revenues in respect of: 'any other costs which the Authority shall determine, upon an application to it by the Licensee shall be included as excluded transmission and distribution costs'.[9]

14.12 NIE said that it had incurred operating costs in relation to the Enduring Solution IT project for the period up to 31 December 2012 of £5.4 million. However, the UR only approved £4.1 million of these costs. NIE said that it considered that the relevant operating costs associated with the Enduring Solution system had been efficiently incurred and NIE should have been entitled to recover them. It said that the UR had not provided any reasonable rationale for disallowing costs, but had merely referred to having applied the same considerations as are applied in the Final Determination for RP5, in disallowing part of NIE's forecast Enduring Solution costs.[10]

[8] UR Supplementary Submission, section 12.
[9] NIE Statement of Case, Chapter 12, section 3.
[10] ibid, Chapter 12, section 3.

14.13 The UR argued that NIE was requesting that we should review a decision that the UR had already taken in RP4. It had considered NIE's request under the D_t mechanism and granted it in part. It said that the statutory framework did not provide for any appeal process from such decisions, but NIE could have sought judicial review of it. The UR argued that we need not investigate this issue.[11]

Interpretation of the capital allowances term in the RP4 price control

14.14 NIE said that the provisions of the RP4 price control which regulated the return which NIE may earn on capital employed allow for a basic return to be adjusted by an amount in respect of NIE's tax liability on such return, so as to provide for NIE to earn an appropriate post-tax return. The calculation provided for adjustments to be made for non-network capex, depreciation, interest and capital allowances. The adjustment for capital allowances (CA_t) provides that there should be deducted from the base return: 'an amount in pounds sterling equal to the level of capital allowances agreed with HM Revenue & Customs in respect of relevant year t calculated in accordance with the Capital Allowances Act 2001 (or successor legislation) and relevant industry agreements or rules'.[12]

14.15 NIE said it considered that the CA_t term should be construed as referring not to the total amount of capital allowances theoretically available to NIE in year t, but to the allowances claimed and offset against NIE's taxable profits. It said that the UR took the converse view, namely that the CA_t term should be construed as referring to the maximum amount of capital allowances available to be claimed in year t, on the basis that NIE should not be permitted to increase customers' bills by choosing not to optimize the tax position of the regulated T&D Business.[13]

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[11] UR Supplementary Submission, section 12.
[12] NIE Statement of Case, Chapter 12, section 4.
[13] ibid, Chapter 12, section 4.

14.16 The UR has required NIE to set its tariffs from 1 October 2010 on the assumption that the CA_t term requires NIE to take account of the maximum available capital allowances, rather than the capital allowances claimed in 2008/09 and in successive years. NIE said that this approach entailed it forgoing RP4 revenues of £0.9 million, in respect of the 2008/09 disclaim, relative to the revenues to which NIE would be entitled by reference to its proposed reading of the CA_t term.[14]

14.17 It submitted that the UR's interpretation of the CA_t term was wrong, and it was inconsistent for the UR to seek to reverse the 2008/09 capital allowances disclaim but not to similarly reverse the 2006/07 disclaim. NIE said the 2006/07 disclaim had no adverse effect on customers (as the price control provided for a pre-tax return), but benefited customers in future years by ensuring that a larger pool of capital allowances would be available to be offset against taxable profits in future years. NIE argued that the UR should take account of the overall effect of NIE's approach, and should recognize the combined impact of the disclaims on customers. NIE also said that, to the extent that there would need to be a CA_t term in the RP5 price control, it would be helpful if we would clarify how it should be applied, and so that it was clear what was, for regulatory purposes, the value of the residual pool of capital allowances available to NIE at the opening of RP5.[15]

14.18 In response, the UR characterized NIE's request as effectively asking us to review the UR's legal interpretation of a particular provision of NIE's RP4 price control. It said that this was a matter that NIE could have but chose not to raise by way of judicial review. It said that the CC had no jurisdiction to rule on the legal interpretation of the RP4 price control.[16]

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[14] ibid, Chapter 12, section 4.
[15] ibid, Chapter 12, section 4.
[16] UR Supplementary Submission, section 12.

Assessment

14.19 In considering these points, we note that our terms of reference refer us to the price control conditions in each licence at present, with a view of considering whether or not these operate against the public interest. The issues raised above are points of relative detail and/or divergence of interpretation between the parties relating to the implementation of the RP4 controls. Such issues would be a matter for the UR and NIE to resolve. NIE pointed out that resources consumed by judicial review could be prohibitive if matters were not decided quickly and fairly. Nonetheless, given our terms of reference, it is not obvious why these should engage the CC for the purpose of its redetermination.

14.20 In addition, where the implementation of a price control that has been agreed for a five-year period requires decisions by the regulator during that period, it could harm the public interest for the CC to go back and replace the decisions of the regulator with its own decision. This could lead to regulatory uncertainty, for example if all decisions were up for redetermination at the next review even if they were taken several years previously.

14.21 However, we do consider that previous determinations may arguably be relevant to our redetermination, for example if they affect recoverable revenues in RP5 through the RAB. In particular, we accept that there may be particular circumstances, such as a previous technical error by the regulator, when it may be appropriate to revisit elements of past determinations that continue to have an impact on the current price control. From the perspective of considering these points under the public interest test, much would depend on how significant or material these are in terms of substance. If we believed that the points raised under these headings were important enough and/or that something has gone substantially wrong to the extent that not addressing it now would lead to adverse outcomes significant enough to contravene the public interest, then we think that we could consider it in more detail.[17]

14.22 On the first point, RP4 capex efficiencies, we note that the UR has commissioned an audit of these efficiencies and is making a decision on this basis. While the delay in reaching its determination may be unfortunate, no evidence has been provided to us to indicate either that this is a relevant point for our redetermination, nor that the UR has made any kind of technical error, resulting in materially adverse effects on consumers, in its assessment. NIE has not pointed to any particular circumstances that indicate that a substantial impact adverse to the public interest is carried into RP5. We conclude that this is an issue regarding the implementation of the RP4 licences that does not fall into the scope of the CC's redetermination.

14.23 On the second point, we agree with the UR that it has undertaken its assessment and reached a decision. Again, NIE has not pointed to any particular circumstances that indicate that a substantial adverse effect on the public interest is carried into RP5.

14.24 However, we address allowances for Enduring Solution, as a new controllable opex activity, in paragraphs 10.113 to 10.179. We have to consider an appropriate opex allowance for ongoing activities in RP5. The sum under issue here relates to expenditure on Enduring Solution in the period from April to December 2012, and so falls within the period that we have assessed in that section. Under these circumstances, we consider that the disputed expenditure can be classed as an RP5

[17] NIE suggested a variety of other reasons as to why it may be appropriate to correct past errors or resolve issues from the previous price control. Some of these points are clearly relevant to a redetermination of the current type, such as where issues refer to events within the period covered by the new price control period, or the error undermines confidence in the fairness and effectiveness of the regulatory system to a material extent such that the public interest going forward is adversely affected. We do not agree that past decisions should be corrected just because evidence or reasoning used in setting the new control conditions has evolved, or because a variety of separate issues can be added together to make a more material impact.

issue and appropriate allowances for it are to be set under our determination of opex allowances—see paragraph 10.179.

14.25 On the third point, the essence of NIE's argument is that the UR's interpretation of the CA_t term is wrong, and that it has acted inconsistently in the treatment of dis-claims in different years, which give different benefits and costs to consumers and NIE in the long term.

14.26 We do not believe that it is appropriate for us to address arguments that relate mainly to a difference in interpretation or other disagreement between NIE and the UR on their understanding of what the licence says in relation to past control periods. It does not seem likely that these differences in interpretation of the rules give rise to what may be a material error. We did, however, consider whether there may be issues around inconsistent application of the interpretation of the licence and whether these would be sufficiently material to potentially operate against the public interest. We note that the correction proposed by NIE amounts to £0.9 million. In this context, whether or not there has been some kind of technical error, it is not obvious that a one-off adjustment of up to £0.9 million (in past, non-capitalized, revenue allowances) constitutes a sufficiently material error, such that aspects of a past determination should be revisited. In our judgement, we do not consider that NIE has demonstrated sufficient grounds for us to believe that the UR's interpretation might be incorrect or inconsistent with a sufficiently substantive impact, so as to justify reconsideration of this point.

14.27 However, we note that that it is important to reduce the risk of ambiguity and dispute in the future where it is possible to provide clarity on interpretation of rules upfront ahead of the implementation of a new price control. Further, modelling the new price control requires assumptions to be made on what capital allowances will be available to NIE. For the purposes of the provisional determination, we have followed the UR's interpretation in our modelling. We will review this approach in the light of responses to the provisional determination.

Conclusion

14.28 For the reasons set out above, we have decided not to investigate further or make adjustments for the unresolved RP4 issues identified by NIE in relation to RP4 capex efficiency incentive payments or interpretation of the capital allowances term in the RP4 price control. Our evaluation of costs for the Enduring Solution project for April to December 2012 is set out in Section 10.

15. NIE’s capitalization practices

Introduction

15.1 The UR asked us to investigate whether changes in NIE’s capitalization practices meant that, in effect, consumers had paid twice for certain activities in RP4. It suggested that this might have arisen because the design of the RP4 price control could have allowed the same activities to be funded, once via the opex allowance and then again via the capex allowance.

15.2 The UR further argued that this double funding had contributed to NIE’s substantial outperformance of its RP4 opex allowance. As a result, an additional £31.7 million of expenditure had been added to NIE’s RAB, rather than having been expensed as opex, the accounting treatment which would have occurred had NIE maintained consistent practices throughout the period. The UR therefore proposed that there should be a downward adjustment of £31.7 million to the RAB at the outset of RP5 to unwind the impact arising from the alleged changes in accounting practices which NIE made during RP4 (and RP3).

15.3 The first issue we therefore consider in this section is whether the design of the previous price control, RP4, via the incentives it created, acted in the public interest and, if not, how we might ensure through the design of RP5 that any such incentives might be removed or mitigated in future. We therefore explore and provisionally conclude on this issue and provide a link to where these issues are taken into account in the design of NIE’s RP5 licences.

15.4 The second issue we consider and provisionally conclude on is whether, as the UR has proposed, we should make an adjustment to the value of NIE’s RAB at the outset of the RP5 price control. In addressing this question we identified a further issue, namely the appropriate regulatory asset life that should be adopted for short-lived assets for future pricing purposes. At the end of this section we explore this issue and provisionally conclude on the approach that should be adopted in future.

15.5 The section is therefore structured as follows:

(a) the UR's concerns over NIE's capitalization practices (paragraphs 15.6 to 15.31);

(b) the design of RP4 and the public interest (paragraphs 15.32 to 15.37);

(c) assessment of whether there should be a regulatory adjustment to the RAB because of the effect of changed capitalization practices (paragraphs 15.38 to 15.87); and

(d) evaluation of the regulatory asset life for tree cutting in the public interest (paragraphs 15.88 to 15.92).

UR's concerns over capitalization practices

15.6 One of the issues the UR asked us to consider in relation to the setting of the RP5 price control was whether there should be a downward adjustment to the opening value of NIE's RAB arising from changes in NIE's capitalization practices,[1] which the UR alleged that NIE had made during RP4 and RP3. The UR argued that changes that NIE had made to the way in which it classified the expenditure on certain activities between opex and capex had contributed to NIE's substantial outperformance of the controllable opex allowances it had been granted over the period 2005/06 to 2011/12.

15.7 The extent of, and the trend in, NIE's outperformance of the controllable opex element of the price controls it was subject to over RP3 and RP4 is illustrated in Table 15.1.

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[1] Capitalization practices means the categorising of expenditure for accounting purposes between that relating to an asset, in this case fixed assets, or not. See paragraph 15.12 for a discussion of fixed assets.

TABLE 15.1 **NIE's outperformance of its controllable opex allowance across RP3 and RP4, 2009/10 prices**

£ million

	RP3					*RP4*					*Totals*		
	02/03	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*	*∑RP3*	*∑RP4*	*% ∆ RP3 to RP4*
Allowance	71.4	61.5	57.9	54.0	44.8	50.4	44.8	43.9	33.9	29.1	289.7	202.2	(30)
Out-turn	53.4	46.6	43.9	33.9	29.1	28.5	27.2	29.1	27.5	27.7	206.9	140.0	(32)
Outperformance	18.0	14.9	14.0	20.1	15.7	21.9	17.6	14.8	6.4	1.4	82.8	62.2	(25)
% outperformance	25	24	24	37	35	43	39	34	19	5	29	31	

Source: NIE.*

*The allowances for 2007/08 and 2008/09 are different from out-turn costs in 2002/03 and 2003/04 because of adjustments that the UR made to these out-turn costs to set allowances for the first two years of RP4. These adjustments were £3.0 million and £1.8 million respectively in 2009/10 prices. Source for the value of these adjustments is Table 1, p7, of the December 2005 RP4 initial proposals document. See paragraph 15.18 for an explanation of the relevance of this point.

15.8 The elements of NIE's controllable opex which the UR brought to our attention in its submission in relation to NIE's outperformance of its controllable opex allowances related to:

(a) tree cutting (an element of routine maintenance);

(b) repairs and maintenance; and

(c) support activities attributable to capex items ('overheads').

15.9 In relation to the last element NIE had estimated the amount of total overhead costs incurred that were attributable to capital items and deducted that to arrive at controllable opex.

15.10 The total contribution of each of the elements as set out in paragraph 15.8 to total controllable opex over a 12-year period between 2001/02 to 2011/12 is set out in Table 15.2.

TABLE 15.2 **Contribution of activities to NIE's controllable opex between 2000/01 and 2011/12, 2009/10 prices**

£ million

	RP2		*RP3*					*RP4*				
	00/01	*01/02*	*02/03*	*03/04*	*04/05*	*05/06*	*06/07*	*07/08*	*08/09*	*09/10*	*10/11*	*11/12*
Repairs & maintenance excluding tree cutting	18.2	16.1	13.8	13.7	13.4	11.0	10.0	9.8	10.0	9.1	9.6	10.5
Tree cutting	0.1	0.8	0.9	0.7	1.5	0.9	0.7	0.4	0.4	0.6	0.5	0.3
Repairs & maintenance including tree cutting	18.3	16.9	14.7	14.4	14.9	11.9	10.8	10.2	10.5	9.7	10.1	10.8
All other costs including capitalized overheads	61.2	53.7	47.8	42.8	38.1	31.2	28.3	27.6	25.9	28.2	26.4	25.8
Total costs before capitalization of overheads	79.5	70.6	62.5	57.2	53.0	43.1	39.0	37.8	36.3	37.8	36.5	36.6
Less capitalized overheads	–6.3	–8.1	–9.1	–10.6	–9.1	–9.2	–9.9	–9.3	–9.1	–8.7	–9.0	–8.9
Total controllable operating costs	73.2	62.5	53.4	46.6	43.9	33.9	29.1	28.5	27.2	29.1	27.5	27.7

Source: NIE.

15.11 There are some discrepancies in the out-turn controllable opex numbers in 2009/10 prices in the analyses provided by the UR and NIE, and therefore the precise extent to which NIE outperformed this allowance in RP3 and RP4. This situation arose because the UR had not been able fully to take into account NIE's out-turn costs restated in 2009/10 prices, particularly in relation to 2011/12, when making its submissions to us. On the advice of the UR, we used numbers supplied by NIE in our review of the cost evidence, both here in Section 15 and in Appendix 15.1, as NIE would be able to supply us with final out-turn numbers across the whole period of analysis up to and including 2011/12. While there are some differences between the numbers provided by the UR in its submissions and NIE, we do not consider that the extent of these differences is material to the reasoning and provisional conclusions set out in this section.

Nature of the distinction between opex and capex

15.12 Capex relates to expenditure on fixed assets. Fixed assets[2] are items where it is expected that longer-term future economic benefits will accrue to their owner, in this case from their use in the business of supplying electricity to the customers of NIE.

[2] Fixed assets represent the productive capacity of a business and are intended for use in the business on a longer-term basis. In this context 'longer-term' means expected to provide economic benefits in accounting periods beyond the balance sheet date.

Only expenditure on assets should be capitalized, not least so that their cost can be matched to revenues earned in future accounting periods. All other expenditure should be expensed as opex to the profit and loss account in the period in which they are incurred.

15.13 Much of NIE's expenditure, whether of a capital or operational nature, relates to subsequent expenditure on existing fixed assets, ie expenditure on already existing fixed assets that maintains these assets in proper working order and/or replaces part(s) of the asset when those part(s) fail or are due to fail. All the activities which the UR highlighted primarily relate to this category of expenditure. NIE's fixed assets mainly comprise its network of overhead and underground transmission and distribution lines and its network of substations. NIE has described its overhead lines as 'perpetual assets', and this description can be applied more broadly to all its network assets.

15.14 Perpetual assets are where components of the broader asset are replaced continuously in cycles, rather than the complete asset being replaced at end of life.[3] In other words, although the individual components of the composite asset do not last forever, NIE's intention is that the composite asset shall remain in working order in perpetuity.

15.15 Subsequent expenditure on existing assets can be categorized between opex and capex and, as we shall see later, between planned and reactive work. This is illustrated in Appendix 15.1, Table 2.

[3] Section 5.3.4.1, Refurbishment: www.nie.co.uk/documents/Policy-Statements/Asset_mgmt_strategy.aspx.

The UR's concerns about NIE's capitalization practices in relation to NIE's outperformance of its controllable opex allowances

15.16 The UR told us that it had been concerned by the development of NIE's opex outperformance over time. It said that the reduction in controllable opex achieved by NIE between 2004/05 (£43.5 million[4]) and 2006/07 (£29.1 million) was extraordinary in that a business that had been in the private sector since 1992 was suddenly able to reduce its controllable opex by more than one-third (in real terms) in the space of two years.[5]

15.17 Opex outperformance arises where a regulated company spends less on opex than the ex ante allowances it has been given. It is allowed to retain all or a proportion of that saving. However, typically opex allowances will be reset at the next price control taking account of this reduced opex expenditure. Outperformance is therefore intended to act as a short-term incentive mechanism to encourage efficiencies which are later passed through to customers.

15.18 The UR said that the reduction in opex needed to be understood in the context of the incentives that were in place in respect of opex and capex at the time. In RP4, controllable opex was remunerated on a rolling 'allowance' basis based on opex expenditure five years previously. In contrast, capex was remunerated on a pass-through basis (see paragraph 3.9). The UR said that it followed that, if NIE could find a way to classify as capex in RP4 expenditure that had previously been treated as controllable opex, it would retain the allowance for opex (ie as outperformance) and, in addition, benefit from an increase in its RAB. That process of reclassification would therefore increase NIE T&D's profit by £1 for every £1 of expenditure shifted. That extra £1 would come from customers, who could pay twice for the same expenditure: once

[4] The outperformance figure quoted by the UR are as per its submissions, whereas the figures in Table 15.1 reflected a figure provided by NIE.
[5] UR Statement of Case, UR6, paragraph 4.

through NIE T&D's opex allowance in RP4 and again over the following 40 years as a result of the increase in RAB.[6]

15.19 The UR told us that its investigations had revealed that NIE had changed its approach to capitalization in December 2005 (and noted that a new version of NIE's Network Capital Expenditure Procedures Manual had been issued at that time which revised its guidance on cost classification). It said that there was evidence of £35.6 million of opex being reclassified as capex over the course of the final two years of RP3 and the five years of RP4. It noted that the proportion of tree-cutting expenditure classified as capex increased from an average of 33 per cent in 2003 to 2005 to 88 per cent through RP4. It noted that the proportion of repairs and maintenance channelled through NIE's sister company, NIE Powerteam, classified as capex increased from 58 to 71 per cent from 2004/05 to 2010/11. It also said that NIE had increased its capitalization rates for indirect costs.[7] The UR said that while it had identified these three areas of activity as showing cost reclassification, it was possible that other areas might also be affected, although it offered no evidence of this.[8]

15.20 The UR therefore invited us to consider whether NIE's opex saving (in RP4 and the last two years of RP3[9]) was the consequence of changes in accounting approaches, whether customers in effect were being required to fund work that had been capitalized into the RAB but which had already been covered by NIE's RP3/RP4 opex allowance, and if so whether any actions, such as an adjustment to the RAB, should be taken.

[6] ibid, paragraph 5.
[7] ibid, paragraph 6.
[8] The UR suggested that tower painting; line patrols and line survey work; unproductive time, including design costs for projects that were not commissioned; and the treatment of NIE Powerteam costs in general, could all be suitable for further investigation (UR Statement of Case, UR6, paragraph 13a).
[9] The UR sought to make an adjustment in respect of the last two years relating to the RP3 period (ie in relation to both 2005/06 and 2006/07) as it was from 2005/06 that it had concluded that a marked increase in capitalization of expenditure had occurred. To the extent that the structure of RP3 replicated the risk that some expenditure could be funded twice, then consumers would also risk paying higher prices than they otherwise would have.

15.21 In its final determination, the UR proposed to reduce NIE's RAB by an amount it calculated to correspond to this overpayment. It said that it believed that was the minimum that must be done, as any other approach involved knowingly requiring customers to pay again over the next 40 years (through the depreciation of, and return on, the RAB) for the work that they had already paid as opex during RP3 and RP4.[10]

15.22 It referred to the CC's *Phoenix Gas* report, which states:

> 5.89 The intention of rewarding outperformance is to encourage the achievement of efficiencies. Therefore outperformance should be an accurate reflection of cost savings that were efficiently incurred, rather than where, for example, the regulated company provides deliberately misleading information to the regulator or where the regulator made a technical error (eg a calculation error).
>
> 5.103 … We think that funding PNGL twice for the same expense is a technical error and that this would operate against the public interest.

15.23 The UR indicated that its concerns did not depend on changes in the precise accounting policies and practices adopted by NIE. Rather it said that there had been at least changes in accounting estimates (ie the detailed application of accounting principles), and its analysis had shown that there were changes in accounting estimates that had a material impact on the allocation of costs between opex and capex.[11] It also said that it did not assert that any accounting rules had been broken.[12] Its submissions make reference to its view that changes in capitalization

[10] UR Statement of Case, UR6, paragraph 14.
[11] UR Final Determination, paragraphs 4.55–4.57.
[12] ibid, paragraph 4.58.

had not been shown to reflect changes in NIE’s underlying activities within the relevant cost categories.[13]

The background to the design of the RP4 charge control

15.24 The UR told us that the design of the charge control (as explained in paragraph 15.18) did not reflect normal regulatory practice but in fact was unusual and partly derived from an NIE ‘composite’ proposal to the UR from March 2005 for the basis of the RP4 price control settlement. NIE presented this proposal to the UR as *(a)* a way of saving costs ‘the cost of efficiency studies is avoided’, and *(b)* ‘the use of actual expenditure to determine future entitlement removes ambiguity around the allocation of costs between opex and capex. For regulatory purposes actual expenditure is recovered either via the RAB over 40 years or via the opex allowance but not both’.

NIE’s response to these concerns

15.25 NIE said that it firmly rejected the UR’s case for the proposed adjustments to the RAB. NIE said that the final determination represented an attempt to reopen the RP3 and RP4 price controls, without any compelling reason and without regard to the UR’s wider statutory duties and objectives.[14] NIE submitted that much of the determination was misconceived as it was based on assumptions which were incorrect, and it addressed questions which were, in principle, irrelevant to the setting of the RP5 price control.[15] It also said that it had not, in any relevant sense, changed its capitalization practices.[16]

15.26 NIE acknowledged that it had outperformed its RP4 controllable opex allowance by £62 million (amounting to some 3 per cent of regulated revenues for RP4). It said that it considered that this outperformance was a legitimate return to NIE under the

[13] For example, UR Statement of Case, UR6, paragraph 9, third sentence.
[14] NIE Statement of Case, Chapter 11, paragraph 1.10.
[15] ibid, Chapter 11, paragraph 1.8.
[16] ibid, Chapter 11, paragraph 1.8.

system of RPI–X incentive regulation, having regard to the efficiency of its operations, and it said that the UR had failed to recognize that the RP4 price control had worked to the benefit of customers.[17]

15.27 NIE's analysis of its outperformance of its controllable operating cost allowance for RP4 is shown in Table 15.3.

TABLE 15.3 **RP4 opex outperformance, 2009/10 prices**

	£m
Repairs & maintenance costs	15.6
IT and telecoms costs	11.3
Salary costs	9.6
Corporate costs	8.5
Managed service costs	8.4
Other reductions	4.6
Insurance costs	4.2
Total	62.2

Source: NIE Statement of Case, Table 15.10.1 (rows have been reordered).

15.28 NIE said that the outperformance results showed that RP4 worked well, in that it had driven reductions in NIE's opex and had enabled NIE to adopt new and more effective ways of managing its assets, and these reductions in costs were factored into the assessment of allowable costs for RP5.[18]

15.29 NIE said that the case advanced by the UR for an adjustment to the RAB was not compelling. It said that any argument that there would be double-charging during RP5 or beyond, if NIE were allowed to retain its existing RAB, was misconceived, and rested on an assumption that the RP3 and RP4 opex allowances were 'earmarked' to cover particular costs which NIE had instead capitalized. It said that this was simply incorrect.[19]

[17] ibid, Chapter 11, paragraphs 1.7–1.8.
[18] ibid, Chapter 11, paragraph 2.10.
[19] ibid, Chapter 11, paragraph 6.1.

15.30 It said that the UR had failed to justify the amount of the proposed RAB reduction. It said that the UR's report (from CEPA[20]) was fundamentally unsound. For example, it stated that the analysis did not distinguish between changes in capitalization practices and changes in NIE's underlying activities. [21] It said that the UR had not addressed whether NIE had experienced additional opex costs in relation to any other items which were not covered by the carry-over of opex from RP3. It said that the UR failed to recognize the gains to efficiency arising from increased capex (such as overhead line refurbishment) with the resulting reduction in opex maintenance costs, more accurate cost analysis, and enhanced accuracy and transparency, which would bring lower opex costs, better data and a more modern network in the future.[22]

15.31 NIE said that within the context of regulatory systems, there was a very strong presumption against a retrospective reduction in the RAB. It said that any discretionary ex post RAB reduction should not proceed without also taking account of other potentially countervailing factors such as the effect on confidence in the regulatory regime. It stated that ex post adjustments were bound to diminish confidence in the predictability and fairness of the regulatory regime, and to prevent NIE from raising finance as efficiently as it otherwise could, to the ultimate detriment of consumers. [23]

The design of RP4 and the public interest

15.32 First, we address whether the design of the RP4 price control that has given rise to the capitalization concern operates in the public interest. As noted in paragraph 15.18, the current (RP4) regime has an asymmetric approach to opex and capex. Recovery for opex is an allowance set by the regulator based on costs relating to the five previous years (ie 2002/03 to 2006/07 opex actuals are the basis for RP4 2007/08 to 2011/12 opex allowances), whereas the recovery for capex reflects actual

[20] Cambridge Economic and Policy Associates.
[21] NIE Statement of Case, Chapter 11, paragraph 6.1.
[22] NIE Supplementary Submission, Annex 9, paragraph 6.1.
[23] NIE Statement of Case, Chapter 11, paragraph 6.1.

expenditure[24] in the RP4 period, ie 2007/08 to 2011/12. The approach to opex recovery can be characterized as a 'rolling opex' mechanism and the approach to capex recovery as 'cost pass-through'.

15.33 There are alternative interpretations of why the UR might have set a rolling opex allowance. It could be that this was simply a basis for setting part of an overall expenditure allowance for NIE to decide how to spend. Alternatively, it might be viewed as representing a means of funding opex activities assumed to be repeated from those five years earlier, unless specific adjustments had been made for then current, or discontinued, activities. The RP4 determination documentation does not show whether either of these interpretations corresponded to the UR's intentions.

15.34 On the second interpretation, the design of the price control carried the risk that, to the extent that any expenditure on continuing activities captured historically under opex could be validly reclassified prospectively as capex, such expenditure could be funded twice. Therefore the design of the price control made it susceptible to changes in the implementation by NIE of its capitalization policies, and gave NIE an incentive to make such changes. As a result, there was a risk that consumers would pay higher prices than they otherwise would have had the implementation of capitalization policies remained consistent throughout.

15.35 NIE told us that it was actively seeking to make sure that it identified all expenditure on replacement assets as capex. Consequently we expect that any reclassification would primarily be from opex to capex.

15.36 We provisionally conclude that this RP4 design gives rise to a real risk that NIE is incentivized to reclassify expenditures from opex to capex, and the result is that cus-

[24] NIE, however, regarded itself as being subject to an overall budget for capital expenditure. For a fuller discussion of the extent to which NIE was subject to a cost-pass-through constraint—see paragraphs 3.29–3.38.

tomers will additionally have to pay for an investment in the RAB for an expenditure that was notionally covered in the operating allowance. We provisionally conclude that this may be expected to operate against the public interest.

15.37 See also Section 5, which discusses different potential designs for a new charge control. Our proposals on cost risk-sharing[25] take into account the experience of the operation of the RP4 price control as set out in this section.

Assessment of whether there should be a regulatory adjustment to the RAB because of the effect of changed capitalization practices

15.38 Having determined that the RP4 price control design operates against the public interest, we consider whether we should now make a regulatory adjustment in order to protect consumers from possible adverse effects arising from the operation of the capitalization issues in RP4 and part of RP3, for example through a reduction in NIE's RAB to strip out past capex, or some other adjustment to compensate for possible excess opex allowances.

15.39 Our finding in paragraph 15.36 above refers to the possibility that the structure of the RP4 control could lead to double funding. In this subsection, we seek to assess whether there is evidence that this effect arose in practice, and whether it can be identified. We assess whether there are other explanations for the levels of out-performance achieved and whether any changes from opex to capex are justified or efficient, and do not operate against the public interest. Our assessment of the costs of the elements of NIE's controllable opex that the UR brought to our attention, namely tree cutting, repairs and maintenance and capitalized overheads, is set out in Appendix 15.1.

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[25] See paragraphs 5.70–5.117.

15.40 This subsection is structured as follows:

(a) our high-level observations on developments over the period of review following our review of the cost evidence (paragraphs 15.41 and 15.42);

(b) developments in accounting standards and NIE's documentation of its approach regarding the distinction between opex and capex (paragraphs 15.43 to 15.49);

(c) the ability to isolate double funding of expenditures in principle (paragraphs 15.50 to 15.55);

(d) the characterization of the effect on the operation of the price control (paragraphs 15.56 and 15.57);

(e) estimating the extent of the reclassification of opex as capex (paragraphs 15.58 and 15.63);

(f) our provisional evaluation (paragraphs 15.64 to 15.85); and

(g) our provisional conclusion (paragraphs 15.86 and 15.87).

Our high-level observations on developments over the period of review following our review of the cost evidence

15.41 Based on the analysis and discussion set out in Appendix 15.1 over the period we have reviewed, there appeared to have been four significant developments affecting subsequent expenditure on existing assets, the category of expenditure into which tree cutting, repairs and maintenance and capitalized overheads primarily relate to:

(a) NIE had greatly increased the extent to which it undertook tree cutting as part of its overhead line rolling programmes (ie change in scale of an existing activity).

(b) NIE had undertaken a number of initiatives including, for example, investing in assets, such as at substations, that had lower ongoing maintenance requirements (ie change in activities).

(c) NIE had adopted a more systematic/programmatic approach to managing existing network assets (ie change in approach from reactive work to planned programmes).

(d) NIE had pushed to identify fully that element of its total subsequent expenditure on existing assets (whether planned or reactive) that constituted the replacement of existing assets, and therefore should be treated as capex rather than opex (ie reclassification of spend).

15.42 In addition, an analysis of the development of controllable opex over RP3 and RP4 suggested that the scale of NIE's outperformance was unlikely to be attributable in large part to the reclassification of opex as capex.

Developments in accounting standards and NIE's documentation of its approach regarding the distinction between opex and capex

15.43 The UR characterized what had occurred, particularly since 2005/06, as NIE changing its capitalization policies/practices/procedures such that there had been a switch in the classification of some expenditure from opex to capex. As part of our review, we therefore reviewed the accounting standards in force over the period of review to see if they could inform whether what had occurred was in the public interest or not. We also looked at the NIE documentation of the approach it had taken towards capitalization that the UR had referred us to. This assessment is set out in Appendix 15.2.

Our characterization of the developments in NIE's approach to capitalizing expenditure

15.44 As discussed in Appendix 15.2, from our review of the documentation it is evident that there had been a change in approach by NIE towards capitalizing some subsequent expenditure on existing assets, this change in approach being embodied in the switch in accounting standards from UK (Approach A[26]) to international accounting

[26] If the asset has been given a single asset life, then any further expenditure on the asset subsequent to its creation, but before the wider asset has come to the end of its expected useful economic life, should be expensed. See Appendix 15.2, paragraph 8, for a fuller explanation.

standards (Approach B[27]). However, this shift in approach does not appear to have manifested itself in any sharp increase in capitalization from one particular accounting period to the next.

15.45 What appears to be more the case from our review of the costs of tree cutting and repairs and maintenance, and the explanations NIE provided in relation to these costs, is that NIE has invested in a number of its management and information systems, to identify all expenditure that in accordance with Approach B should be capitalized, ie all expenditure on the replacement of assets. At the same time, NIE has also increased the level of existing activities which it capitalizes (eg programmed tree cutting) as well as changing the activities it undertook as a result of a shift of emphasis towards planned (generally capitalized) programmes rather than reactive work. All these factors, among others, may have contributed to the observed trends in the relative amounts of expenditure capitalized to that expensed. The increase in the proportion of expenditure capitalized over time reflects the switch in approach towards capitalizing expenditure embodied in accounting standards but began before NIE adopted international accounting standards in 2005/06.

15.46 NIE's investment in its management and information systems can be characterized as NIE improving its ability over time to implement its policy towards capitalizing all of expenditure on replacement assets. Under accounting standards (both UK and international), changes to reported costs as a result of a firm's increased ability to implement fully a chosen accounting policy do not count as a change in accounting policy.

15.47 As mentioned in Appendix 15.1, NIE also bundled some activities previously classified as opex repairs and maintenance into its capital programmes. To the extent that such expenditure qualifies as expenditure on replacement assets, then this develop-

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[27] Expenditure relating to the replacement of parts of a wider asset should be capitalized. See Appendix 15.2, paragraph 9, for a fuller explanation.

ment can be seen as part of the same overall trend whereby NIE seeks to identify all its asset replacement expenditure in order to capitalize it.

15.48 In summary, we found no indication that NIE had breached either any rules specified by the regulator or any rules in the accounting standards regarding what expenditure NIE had in fact capitalized. There was, however, a clear indication that NIE had over time got significantly better at identifying all its expenditure on replacement assets.

15.49 From our analysis of expenditure, it is apparent that the trend to capitalize an ever greater proportion of NIE's total expenditure on replacement assets (relating to both tree cutting and more generally repairs and maintenance) began well before the end of RP4 in March 2007. However, the UR did not request copies of NIE's capitalization policies until June 2010. This was nearly four years after the regulatory financial statements for 2005/06, published in September 2006, had shown a £10 million drop in controllable opex compared with the total for the previous year.

The ability to isolate double funding of expenditures in principle

15.50 We considered the circumstances under which the UR's concern could be realized, that specific expenditures could be financed both through an opex allowance based on past opex, and a new capex allowance because of reclassification of expenditures to capex as a result of changes in capitalization practices.

15.51 First, we recognize that this effect might arise were the same activities simply to be relabelled. However, no such effect would arise if NIE had increased capex without reducing opex in absolute terms, as no reclassification between them would occur, despite the changes in proportions of opex and capex.

15.52 However, we have seen that NIE has made changes to the way in which it has organized its activities, for example approaching repairs and maintenance or tree cutting in a planned rather than reactive way. It has also changed some of its activities, such as investing in new assets that require less opex-type maintenance.

15.53 The explanations offered for the evolution of the relative mix of opex and capex expenditure indicates that at least some of these developments are likely to be more efficient in the longer term and reduce total costs. We do not think it would be correct to find the treatment of costs in relation to actions taken in order to achieve efficiencies to be against the public interest. Indeed NIE was deliberately incentivized to pursue such efficiencies by the setting of allowances, such as that for controllable opex, which it could outperform. In this context, distinguishing between outperformance arising from the adoption of efficiency-enhancing measures and those stemming from the reclassification of the costs of continuing activities is likely to be extremely difficult. Identifying which cause applies in each particular case is likely to be subjective. We note that no distinction was drawn in advance in terms of directing NIE as to how it was to achieve outperformance.

15.54 We also note that the RP4 determination did not include any direction as to whether there was an expectation that the opex allowance was intended to cover exactly the same opex activities as RP3, even though the allowance was derived from RP3 expenditure. This is consistent with NIE being given discretion to pursue what it saw as the optimal pattern of opex.

15.55 These difficulties indicate that conceptually identifying a distinction where the substitution of opex for capex ceases to be legitimate, and instead represents double funding of expenditures, would be extremely difficult.

Characterization of the effect on the operation of the price control

15.56 In its final determination, the UR estimated the extent to which, in its view, NIE had reclassified opex as capex and had substituted opex activities for equivalent (again, in its view) capex activities at £31.7 million.[28] As a result, the UR proposed that NIE's RAB should be reduced by this amount at the outset of RP5. In other words, the UR's view was that NIE had included £31.7 million of expenditure within its fixed asset additions, which it would not have done had it maintained consistent capitalization practices throughout, and therefore £31.7 million had been incorrectly added to NIE's RAB.

15.57 Under the RP4 price control framework, the starting point for additions to the RAB for any one period are the fixed asset additions as reported in NIE's regulatory financial statements. We therefore consider that, so long as expenditure had been correctly included within fixed asset additions, then additions to the RAB during the RP4 price control would have been correctly established. As we have no reason to doubt that the amount of fixed asset additions has been correctly determined, we therefore consider that the potential excess costs (if there has been double funding) would be better characterized as an excessive opex funding.

Estimating the extent of the reclassification of opex as capex

15.58 Given that there was a risk that customers could end up funding some expenditure once through the opex allowance and again through fixed asset additions (capex) being added to the RAB, and we had been given several examples where NIE had been able to identify all its replacement capex which previously would have remained in opex, we considered how we might isolate the extent of this reclassification effect.

[28] This £31.7 million UR estimate relates to the impact on the RAB as at the end of RP4, whereas the estimate of £35.6 million in paragraph 15.19 reflects the UR's estimate of the reclassification effect in total.

15.59 First of all, we considered the approach the UR's consultants CEPA had taken. For both tree cutting and overheads, the amount of reclassification was estimated using historically determined capitalization rates. The analysis undertaken in relation to repairs and maintenance considered both the amounts transferred out of repairs and maintenance (eg relating to the cost of replacing assets following a fault being identified) and the activities, which in the consultants' view had been captured within planned capital programmes, but still relied in part on estimates using historically determined capitalization rates.

15.60 We considered that this approach was conceptually flawed. The proportion of total costs capitalized is the result of applying a particular approach to capitalization. The fact that this proportion has changed over time is likely to be the result of a number of factors—see paragraph 15.45—only one of which would be any changes in capitalization policy and/or changes in the implementation of a capitalization policy.

15.61 We considered alternative approaches. For example, for repairs and maintenance we calculated the amounts capitalized and expensed each year on average over RP3 and over RP4 and compared the two figures. We then repeated this exercise comparing the annual averages for the period up to and including 2004/05 with the period after 2005/06. We chose this latter split because the period from 2005/06 reflected the period in respect of which the UR wanted to make a RAB adjustment.

15.62 We concluded that, given that over the period: *(a)* NIE had changed the mix of its activities to some extent, *(b)* NIE had adopted an approach to asset management that favoured preplanned capital programmes over reactive repairs and maintenance, and *(c)* there were examples of developments outside NIE's control which were influencing the balance of its spend between capex and opex, there was no approach we could adopt which would robustly isolate the reclassification effect from changes resulting from any of these other factors.

15.63 Given the fact that, at least at a superficial level, NIE's outperformance of controllable operating cost appeared to have been driven by reductions in costs primarily opex in nature (see Appendix 15.1), we are concerned about the risk that any estimate we might calculate would penalize NIE for any efficiency gains that it had in fact generated during RP4 and RP3.

Our provisional evaluation

15.64 NIE acknowledged that there had been some reclassification of opex as capex as a result of NIE's focus on identifying all of its expenditure on replacement assets. However, we have been unable to establish a way of robustly identifying the extent of this reclassification. We judged that the extent of this reclassification was not trivial but did not appear to be the dominant reason why NIE had outperformed its RP4 price control so strongly. Nevertheless consumers, as a result, had paid or would pay in future through higher prices for electricity to some degree than they otherwise would have had this reclassification effect not occurred. We now evaluate whether there is reason to make an adjustment to the outperformance that NIE has already earned.

15.65 There are a number of considerations to take into account. As these factors are inevitably case specific, we set out the ones we believe to be relevant to the case in hand.

Regulatory certainty

15.66 It is in the long-term interest of consumers that there is regulatory certainty for firms such as NIE operating in an environment where they are incentivized, among other things, by the operation of price controls. The regulatory ‘contract’ (or understanding) is that firms, on the one hand, should have the confidence to invest and plan for the future confident that the regulator will not revisit the rules of a regulatory agreement after the event, and that, on the other, consumers should in the longer term reap the benefits of efficiency savings realized through outperformance. Therefore revisiting the terms of previously set price control should generally be avoided because it undermines the regulatory contract or understanding by which firms in regulated industries operate, and therefore their confidence to act long term.

15.67 However, this is not an absolute presumption. An example of where we might disturb a previously agreed regulatory settlement is where an error of a technical nature had been made, for example in setting one of the parameters needed to implement a price control.

15.68 We consider that whilst in the NIE case there has been some element of double funding, we attribute this primarily to flaws in the overall design of RP4, rather than there having been a clearly delineated and misspecified allowance incorporated into the RP4 price control settlement. The flaws gave rise to the risk that NIE would be able to outperform the controllable opex allowance as a result of any improvements that NIE might be able to make in its ability to identify all of its capex. Flaws in the design of a charge control do not in themselves constitute a clearly delineated error that lends itself to correction after the event.

15.69 We therefore do not think that the UR made an error of a technical nature when setting RP4. In any case, the relevant test is the public interest test, not whether there had been a technical error.

15.70 We also note the argument that NIE accepted the RP4 determination as an overall package whereby there are ‘swings and roundabouts’ and it might have accepted certain aspects of the package it felt were unfair if other aspects balanced these out. This notion can be abused if the regulator can cherry-pick elements to reconsider after the event.

Customers funding expenditure on activities more than once

15.71 Northern Ireland consumers should not need to pay higher prices for their electricity than necessary. For the reasons set out in paragraph 15.64, we consider that consumers have paid through higher prices that element of NIE’s outperformance of its controllable opex allowance under RP4 that reflected a reclassification of opex costs as capex.

15.72 In other words, the UR had, through the design of the RP4 price control and the setting of the controllable opex allowance, given NIE incentives to obtain the longer-term benefit of efficiencies in activities funded through the controllable opex allowances for Northern Ireland consumers. However, prices during the RP4 period had been higher than they should have been, given that an element of measured outperformance could be seen to have arisen from changes in classification rather than for any other reason.

15.73 Whilst in principle we accept the UR’s characterization that a simple reclassification of expenditure gives rise to an outperformance that does not reflect efficiency gains, we do not think that the approach that NIE has adopted to classify expenditure as capex is wrong. We also consider that its outperformance of RP4 was much more complex than just a simple reclassification of expenditure of opex as capex.

15.74 We also consider it relevant that the UR had not specified that the rolling opex allowance had been set with the intention of covering similar items of expenditure as had been incurred in the previous period. Rather, it was in effect a general allowance, which NIE was incentivized to outperform in various ways including changes in its mix and levels of opex.

Consideration of the intent of NIE in making changes

15.75 Over time NIE has made a number of changes to the way it operates, maintains and renews its electricity supply network, most notably through a shift from reactive activities to planned activities. NIE has also been able to identify better its fixed asset capex. A factor we considered in weighing the public interest was whether any of these changes, as far as we could ascertain from the information supplied to us, had been done with the intent of undermining the proper operation of the RP4 charge control or otherwise to take advantage of the possibility of double funding. Intent is not of itself part of our assessment (which is evaluated with regard to the overall public interest), but it may help inform our assessment of what has happened.

15.76 With the elapse of time it is not possible to establish the precise intent of NIE *(a)* at the time it made its Composite Proposal for RP4 to NIE, *(b)* when it developed its capex proposals for RP5 which included capital programmes which incorporated to some extent activities previously undertaken as opex and *(c)* through the period when it was enhancing its ability to identify all its expenditure on replacement assets.

15.77 We note that from the UR's perspective there was a lack of transparency on NIE's part in its dealings with it. For example, the UR had not appreciated from the explanations given to it as part of the run-up to RP4 that most, if not all, of the TAR programmes comprised wholly or mainly tree cutting. As mentioned in paragraph 15.49, there appears to have been a lack of ongoing monitoring of subsequent developments once price controls had been set. Had timely monitoring been undertaken, it would have allowed the UR to have much more effectively engaged with NIE and addressed these issues on a timely basis rather was in fact the case.

15.78 We observe, however, that these developments took place within a broader context of NIE seeking to be more planned and programmatic in maintaining its network, a development that is to be welcomed. We also note that developments in accounting standards requiring NIE to capitalize all its expenditure on replacement assets were a factor pushing it to identify all such spend. We therefore have seen no evidence of deliberate intent on the part of NIE to bypass the intended mechanism of the RP4 price control.

The ability to robustly estimate the 'adverse' effect

15.79 A further factor in the mix when deciding whether it would be in the public interest to make an adjustment is whether we would be able to estimate robustly the extent to which consumers had overpaid. For example, we would want to avoid inadvertently penalizing NIE for outperformance of its controllable operating cost allowance through genuine efficiency gains.

15.80 As set out in paragraphs 15.59 and 15.60, we reviewed the UR's approach to estimating the adverse effect and considered alternatives of our own. We consider that there is no reliable way of disentangling the extent of the reclassification from other effects, including those arising from efficiency gains. We therefore concluded that we could not obtain a robust estimate of the 'adverse' effect.

The materiality of the adverse effect

15.81 The amount of the overpayment by consumers is also a factor in weighing up the public interest. Whilst there are difficulties in robustly quantifying the effect of re-classification, we are still able to factor its likely materiality into our evaluation.

15.82 Based on our review of the trends in controllable opex over the period of review as set out in Table 15.2 (paragraph 15.10) and again in Appendix 15.1, Table 10, we consider that NIE's outperformance was not likely to have been attributable mainly to reclassification effects. In particular, there was a substantial decrease in other opex between RP3 and RP4 in relation to which the UR had not alleged that NIE had changed its capitalization practices. This substantial decrease could have accounted for much, if not all, of NIE outperformance of its RP4 operating cost allowance.

The undesirability of revisiting past settlements

15.83 Unlike most of the decisions we are making, this decision regarding NIE's capitalization practices affects the operation and direct consequences of historically determined price controls, namely RP3 and RP4. This contrasts with the determination of the structure and parameters for RP5, which will operate in the future.

15.84 We consider that as a general principle it is undesirable to revisit events occurring during periods covered by past regulatory settlements. This is because the regulator and the firm will have reached settled expectations about the rules applying in the past. In contrast, there are no such settled expectations about what will happen during RP5 because there is, as yet, no final decision.

15.85 In this case, we consider that a very strong public interest case for an adjustment arising from the other factors outlined would be required to justify an adjustment affecting a past settlement.

Our provisional conclusion

15.86 In arriving at our provisional conclusion, we have taken all of the factors outlined in paragraphs 15.66 to 15.85 into account. In the round, we consider that we should not make an adjustment. This is because the primary cause of consumers paying too much was the design of the price control that could give rise to this effect. Because the problem stemmed from a poorly designed price control, rather than from an element of the price control clearly being misspecified, we have not been able to estimate with any robustness the extent that consumers have overpaid. However, looking at the analysis of total controllable opex over the period, we do not believe the reclassification effect to be the primary reason why NIE outperformed its RP4 allowance so significantly. We therefore judge that to make any adjustment would risk penalizing NIE for genuine outperformance. We do not believe that there is a very strong public interest case for making an adjustment affecting past settlements in this case.

15.87 As explained in paragraphs 15.56 and 15.57, we note that any adjustment would be more appropriately described as a correction to a misspecified RP4 controllable operating cost allowance rather than a correction to a miscalibrated RAB going into RP5. This may have implications if we were finally to conclude that, contrary to our provisional conclusion set out in the previous paragraph, an adjustment would in fact be in the public interest. In this latter case, we may also need to consider whether it would be appropriate to make a correction for a misspecified *RP4* allowance, rather than a miscalibrated *RP5* RAB.

Evaluation of the regulatory asset life for tree cutting in the public interest

15.88 As introduced in Appendix 15.2, paragraph 17, there is an issue whether it is in the public interest that tree cutting should have the same regulatory asset life as all other capitalized network expenditure, namely 40 years. This situation is relevant to the prices customers ultimately pay in any one period as it is regulatory depreciation charges based on an expected 40-year life which are reflected in the prices for that period.

15.89 In our view, it is inappropriate for future generations to be paying the costs of investments which have such a short life in relation to the period over which they are being depreciated for pricing purposes (40 years) and which will result in non-trivial differences between the prices charged to customers across the generations. We acknowledge that the RAB is a means of allowing NIE to recover capital investments over a suitable period determined by the regulator, in this case 40 years. However, in the RAB all capital investments are given the same asset life for regulatory depreciation purposes. This is the case even though some assets are very long lived (eg 50+ years), some short lived (eg less than five years).

15.90 In the case of tree cutting, the cost in any one year can be significant and the activity of tree cutting needs to be regularly repeated. In the recent past, NIE has modified its approach to managing vegetation in the vicinity of overhead lines, ie the precise balance of programmed tree cutting (capitalized) and reactive tree cutting (expensed as incurred), with a resultant substantial increase in capitalized tree cutting.

15.91 It is therefore possible that future customers would be paying for up to eight past cycles of tree cutting when only the most recent is relevant to them, whereas current customers would only be paying for a disproportionately small fraction of the capitalized cost currently being incurred. We judge that this situation does not reflect a proper balance between the interests of current and future customers, and is therefore against the public interest.

15.92 We therefore provisionally conclude that NIE should create a separate RAB for expenditure on future[29] capitalized tree cutting whose regulatory asset life should be no longer than five years.[30] In the same vein, we also consider that expenditure on other assets with a similarly short economic useful life, which taken together represent a significant block of expenditure, should likewise be included within a short-life RAB.

[29] By 'future', we mean the period from which our price control redetermination would be effective, namely 1 April 2012.
[30] We understand that it is necessary to cut down trees in the vicinity of overhead lines every three to five years to maintain safety clearance and storm resilience of these lines. We therefore consider that five years should be the upper limit for the period over which the short-life RAB should be depreciated.

16. Financeability

Introduction

16.1 Under section 12 of the Energy Order, the UR has a duty to have regard to the need to secure that NIE is able to finance the activities which are the subject of obligations imposed under Part II of the Electricity Order or under the Energy Order. We conduct a cross-check on the outputs of the financial model combining our assumptions for the WACC and expenditure allowances.

16.2 A key part of the financeability analysis is an assessment of whether the company has appropriate financial resources to pay the interest on its debt. The sufficiency of the financial resources is examined by looking at certain financial ratios, typically comparing different measures of cash flow to interest payable (termed 'interest cover ratios'). Our view of what constitutes the appropriate level of interest cover, and the other relevant ratios, has been informed by discussion with credit rating agencies.

16.3 These agencies provide information to the debt markets that is relevant to the credit quality of industry sectors, countries and specific companies. They publish credit ratings which provide a guide to investors as to the credit quality of the issuer and the likelihood of default. The ratings may be categorized broadly into two classes: investment grade and subinvestment grade.

16.4 The general approach of regulators is to target 'investment grade' credit ratios. NIE is subject to licence conditions to take all appropriate steps to obtain and thereafter maintain at all times an investment grade credit rating (for example, paragraph 4 of condition 9A in NIE's distribution licence).

16.5 Should the financeability assessment indicate problems over the price control period, we will consider the reasons for these problems and consider whether they justify any change to the price control model. We will also consider whether it is reasonable for the company to take action to address the financeability issue, and if so whether the company has reasonable options available to it to do so. These options could include reducing or deferring dividends, calling on parent company support, and raising additional capital from existing or new shareholders.

16.6 As our starting point, we have used the model developed by the UR to review the combined effect of all the individual elements of this provisional determination for its financeability. The UR developed a model which, as its first stage, generated the allowed revenues over the period 1 April 2012 to 30 September 2017 based on its determinations, for example for NIE's capex and opex allowances and WACC over this period. The UR then used the allowed revenues so calculated to help forecast the measures of NIE's financeability over this period which it considered relevant.

16.7 We have modified the UR's model to calculate NIE's allowed revenues over the period 1 April 2012 to 30 September 2017 based on our provisional determination for the values of, for example, capex and opex allowances and WACC. We have then used this model, in particular the values generated by it for depreciation, tax, interest and cash flow, to develop measures of financeability which we consider relevant as described in the following paragraphs. In modifying the UR's model we have made two observations:

- it should be NIE's statutory activities[1] that are required to be financeable rather than the corporate entity in which these activities sit; and
- the model calculates profits on the basis of regulatory deprecation, rather than accounting depreciation from either NIE's regulatory or statutory financial statements, to support the calculation of certain interest coverage ratios. We understand that this approach to depreciation has been adopted in response to feedback

[1] See paragraph 16.1.

that the UR received from rating agencies regarding the measures of profitability which they believe to be most relevant to evaluating the credit risk of transmission and distribution businesses such as NIE's.

16.8 The following sections discuss in turn:

- the views of the UR and NIE (paragraphs 16.9 to 16.18);
- financial ratios to be targeted, including evidence from the ratings agencies (paragraphs 16.19 to 16.37);
- assumptions used in making projections of financial ratios, in particular regarding the company's initial gearing (paragraphs 16.38 to 16.44); and
- provisional results of the modelling (paragraphs 16.45 and 16.46).

Views of parties

The UR's approach

16.9 In its final determinations document, the UR's financeability analysis relied primarily on the post-maintenance interest cover ratio (PMICR).

16.10 The PMICR is defined as:

(operating profit + depreciation – tax – pension deficit repair – non-network capital expenditure – RAB amortization)/interest

Where:

- 'depreciation' is the amount provided for in the calculation of 'operating profit';
- 'non-network capital expenditure' refers to categories of capital expenditure (such as office IT or vehicles) that do not enter the regulatory asset value; and
- 'RAB amortization' is the amount allowed into revenues and deducted from regulatory asset base.

16.11 The UR's financial model calculates the following financial ratios besides PMICR:

- FFO/interest, defined as (operating profit + depreciation – tax – pension deficit repair)/interest;
- FFO/debt, defined as (operating profit + depreciation – tax – pension deficit repair)/net debt; and
- gearing.

16.12 The UR focused on the PMICR. It referred to a threshold value of 1.4 for that ratio quoted by Fitch (with reference to a BBB+ rating for an electricity distribution company). The UR said: 'We regard 1.4 as an acceptable level but regard 1.5 to be a more desirable benchmark'.[2]

16.13 The UR focused its analysis on a calculation of the ratios in a hypothetical scenario in which no investment to accommodate new renewable generation would be undertaken, and in which NIE would not have had amounts deducted from its RAB or from its allowed revenues in relation to the UR's proposals to make an adjustment related to capitalization policy and to disallow pension deficit repair costs associated with early retirement.

16.14 On that basis, the UR decided to allow additional revenues to NIE during its proposed RP5 period. Without the additional revenue, the UR's hypothetical PMICR would have been just above 1.4 at the beginning of the period and just below 1.4 at the end of the period. With the additional revenue, the figure was well over 1.4 at the beginning of the period and nearly 1.5 at the end of the period.

16.15 The UR described its proposed increase in allowed revenues during its proposed RP5 period as an 'NPV neutral fix'. It did not describe any mechanism by which a

[2] UR RP5 Final Determination, paragraph 14.21.

deduction of an amount of revenue equivalent (in NPV terms) as the increase during RP5 would be implemented.[3]

16.16 The UR told us:

> We would like to emphasise once again that it is very important for the CC to treat cost of capital and financeability as two separate work-streams. As we have said previously, we would be very concerned if the CC were to feel a need to revisit and adjust its allowed return when it runs its financial model, irrespective of the financial ratios that it observes in its initial model runs.
>
> For completeness, the available fixes for weak interest cover include (a) dividend retention and equity issuance, (b) issuance of index-linked debt, and (c) NPV-neutral revenue advancement. A backfitted, higher cost of capital is not a suitable fix because it hands shareholders additional value at the expense of customers, when the root cause of weak interest cover is not an inadequate total return but rather the scale of NIE T&D's capital programme and the regulatory convention of allowing only part of the nominal cost of capital (i.e. the RPI-stripped real cost of capital) into the annual price control calculation.

NIE's submissions[4]

16.17 NIE told us that its business would not have been financeable under the UR's proposals. The evidence for this was focused on the claim that the expenditure allowed for by the UR was insufficient to operate the business, and therefore NIE could not in fact achieve the financial performance indicated by the UR's model.

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[3] UR RP5 Final Determination, paragraph 14.28.
[4] NIE Statement of Case, Chapter 17.

16.18 NIE also had a number of comments about specific figures (such as opening balances) in the UR's financial model. The UR told us that the effect of these changes was small.

Target financial ratios

16.19 In order to determine the appropriate target ratios, it is necessary to determine a target credit rating. We note that NIE's licence condition is to maintain an investment grade credit rating, and that no specific target rating within investment grade is set. This provides flexibility for the regulated entity to decide on the appropriate credit rating to target in order to efficiently finance its activities. We saw no reason to be more prescriptive in this regard. However, we note that the typical distribution of ratings in the utilities sector may provide an indication of the appropriate credit rating to adopt.

16.20 In the Bristol Water inquiry, the CC targeted a Baa1/BBB+ rating.[5] In the Airports inquiries, the CC targeted a BBB+ rating for Heathrow and Gatwick and an A– rating for Stansted.[6]

16.21 Table 16.1 sets out comparative investment grade credit ratings for Moody's and Fitch and S&P.

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[5] *Bristol Water plc* (2010).

[6] *BAA Ltd* (2007 report on Heathrow and Gatwick, op cit) and *Stansted Airport Limited, Q5 price control review*, CC, presented to the CAA on 23 October 2008

TABLE 16.1 **Comparative investment grade credit ratings**

Moody's	*Fitch/S&P*	*Description*
Aaa	AAA	
Aa1	AA+	
Aa2	AA	High grade
Aa3	AA–	
A1	A+	
A2	A	Upper medium grade
A3	A–	
Baa1	BBB+	
Baa2	BBB	Lower medium grade
Baa3	BBB–	

Source: Moody's Rating Symbols & Definitions; S&P Credit Ratings Definitions & FAQs; Fitch Definitions of Ratings and Other Forms of Opinion.

Rating agency methodology

16.22 This section provides relevant background on rating methodologies.

Moody's

16.23 Moody's publishes a number of credit rating methodologies for the utility sector, including for regulated electric and gas networks.[7] This sets out the relative weight it attaches to key factors, which are:

- Regulatory Environment & Asset Ownership Model (40 per cent weight);
- Efficiency and Execution Risk (10 per cent weight);
- Stability of Business Model & Financial Structure (10 per cent weight); and
- key credit metrics (40 per cent weight).

16.24 Moody's objective, according to the regulated networks methodology, is for users of the methodology to be able to estimate a company's rating within two alphanumeric notches. The rating indicated by the methodology is based on the combination of the four factors, ie companies that score very highly on regulatory environment and asset ownership model (underpinning a low business risk profile) can sustain weaker financial metrics and still maintain a solid investment-grade rating. The credit ratios

[7] *Moody's Global Infrastructure Finance: Regulated Electric and Gas Networks*, August 2009.

that Moody's publishes in relation to scoring under the methodology are generally expressed in terms of a three-year historical average. In setting credit ratings, Moody's examined forward estimates for credit ratios based on management plans and a range of sensitivities. The rating agency does not publish detailed forecasts or estimates.

16.25 Moody's has a published rating for NIE's parent, ESB, but has not published a rating for NIE on a stand-alone basis. ESB is rated using Moody's EMEA regulated network methodology. ESB's rating had fallen from Baa1, when the rating was first published in January 2011, to Baa3 in July 2011. The rating was downgraded by two notches to Baa3 on 14 July 2011 following a review announced on 18 April 2011 and a downgrade of the Republic of Ireland's credit rating to Ba1 from Baa3 on 12 July 2011. According to the press release announcing the rating action, ESB's ratings 'are constrained by that of Ireland due to the company's inability to disconnect itself from local economic and market circumstances'. Moody's noted that ESB had very strong ratios for the Baa3 category and that the indicated rating under the agency's methodology grid was A3. The outlook for the Irish Sovereign had stabilized recently.

16.26 Moody's ratio guidance for UK Regulated Water and Energy Network Utilities is set out in Table 16.2. Moody's notes that the ratio guidance applies to stand-alone regulated businesses funded on a corporate basis, and that actual ratings may be based on the financial profile of the group or reflect the benefits of structural enhancements. Smaller companies would be expected to exhibit stronger adjusted ICRs for an equivalent gearing ratio.

TABLE 16.2 **Target ratios and indicative credit ratings—UK Regulated Water and Energy***

Moody's credit rating	*Adjusted interest cover†*	*Gearing (net debt/ RCV) %*	*FFO/ net debt* %*	*RCF/ capex‡ %*
A1	2.5–3.5	40–50		
A2	1.8–2.5	50–60	12–20	1.5–2.5x
A3	1.6–1.8	60–68		
Baa1	1.4–1.6	68–75	8–12	1.0–1.5x
Baa2	1.2–1.4	75–85		

Source: CC based on Exhibit 4 of 'UK Water Sector: Speed of Money cannot address Potential Financeability Concerns', 16 May 2013.

*FFO/net debt and RCF/capex ratios are taken from Moody's Global Infrastructure Finance methodology and do not specifically relate to UK utility companies. They are average ratios for A and Baa rating bands.
†Adjusted interest cover = (FFO + (net interest – non-cash interest) – capital charges)/(net interest – non-cash interest) where FFO = funds from operations (cash flows from operations less working capital movements plus net interest expense).
(FFO – dividends paid/capex.

Fitch

16.27 Fitch published a long-term Issuer Default Rating (IDR) and a senior unsecured rating for NIE. The current ratings are:

- IDR: BBB+/Stable Outlook (on a stand-alone basis the IDR would be BBB+/Rating Watch Negative, but the public rating assumes support from NIE's parent ESB, rated at IDR of BBB+/Stable Outlook).
- Senior unsecured: A-/Rating Watch Negative.

16.28 Fitch said that it applied its rating guidelines for UK DNOs to NIE, shown in Table 16.3. In doing so, it recognized that the transmission activity of NIE was benign in terms of the business risk profile of NIE in relation to UK DNOs but scored regulatory risk slightly higher.

TABLE 16.3 **Indicative ratings guidelines for UK DNOs**

IDR	*Senior unsecured*	*Adjusted PMICR*	*Debt/RCV %*
A–	A	<1.9	<60
BBB+	A–	1.6–1.9	60–75
BBB	BBB+	1.4–1.6	75–80
BBB–	BBB	1.3–1.4	85–90

Source: Fitch.

16.29 Fitch said that it focused on average metrics for the regulatory period. It said that ratings were not restricted to the application of these two ratios. Other important factors considered when deciding on the IDR were cash flow generation, operational and regulatory performance, under- and overperformance of opex and capex, liquidity and capital structure, dividend policy, and parent support if appropriate. Fitch generally focused on the five-year outlook but for regulated utilities there was limited earnings visibility beyond the end of the price control. For NIE this meant looking at ratios until September 2017.

16.30 In terms of NIE's ratios, Fitch noted that there was an unusually large divergence in the rating indications from gearing (A–) and PMICR (BBB–). Fitch said that it considered that this was largely a result of the UR setting a WACC similar to that of Ofgem whereas the incentives offered to NIE under the UR regulatory framework were little in comparison with those under the RIIO framework, and NIE's cash cost of embedded debt was relatively high compared with Ofgem-regulated comparators. As a result, modelled cash flows and interest cover were lower for NIE.

16.31 The NIE rating of BBB+/stable was linked to parent support from ESB.

16.32 Fitch told us that the outlook/rating review depended on the results of our redetermination and NIE's subsequent budget review, and that it was looking for assurance that engineering assumptions were realistic to resolve the rating watch.

Standard & Poor's Ratings Services

16.33 On Feb. 13, 2013, Standard & Poor's Ratings Services (S&P) revised to stable from negative the outlook on its 'BBB+/A-2' long- and short-term corporate credit and 'BBB+' senior unsecured debt ratings on NIE.

16.34 S&P said that the ratings on NIE reflected those of its 100 per cent parent, ESB.

16.35 S&P also said:

> The ratings on NIE are also underpinned by its solid position as the sole electricity transmission asset owner and the electricity distribution network owner and operator in Northern Ireland. On 23rd October 2013 the UR published its final determination for the five year price control period Jan 1 2013 – Sept 30, 2017. We view the price control as challenging for NIE and this introduces a level of uncertainty around the regulatory framework in Northern Ireland that we do not generally anticipate when assessing the business risk profile of a regulated utility.

CC discussion on target ratios

16.36 We had some difficulty in determining the relevant target interest cover ratio given the divergence in indications given by gearing and interest cover. NIE's relatively low gearing ratio indicates that it can support a Baa1/BBB+ rating ('solid' investment grade) with a lower interest cover ratio than would otherwise be the case.

16.37 We also had regard to target values for the broader set of credit ratios set out in Table 16.2 as these are outputs from the financial model that we have used. We note from our discussions with credit ratings agencies that the value of particular ratios forms an important part of a broader assessment to assign credit ratings. A broad range of other factors would form part of the overall ratings assessment.

Assumptions for financeability assessment

16.38 The financeability assessment compares projected levels of the credit ratios with target levels. The projected levels of these financial ratios depend on the building blocks of the calculation of required revenue, ie opex, capex and cost of capital. The projected levels of these financial ratios also depend on a number of other assumptions, including capital structure (gearing), the use of index-linked debt or interest rate swaps, and dividend payments. The parties' assumptions in these other areas are shown in Table 16.4, alongside the assumptions in our own provisional analysis.

TABLE 16.4 **Financeability assumptions**

	UR	*NIE*	*CC*
Initial gearing	50%	50%	50%
Inclusion of index linked debt	No	No	No
Dividends assumed	2.85% of RAB (5.7% cost of equity and 50% gearing)		2.35% of RAB

Source: CC.

16.39 We discuss the assumptions for initial and average gearing, index-linked debt and dividends further below.

The gearing assumption

16.40 In some circumstances it may be appropriate to reduce the company's initial gearing and recalculate the WACC using a lower level of gearing. The financial projections are then rerun on the basis of the lower gearing and the revised WACC. This process continues until projections suggest that the company is financeable (or a minimum level of gearing is reached). This was broadly the approach to setting gearing used by the CC in Bristol Water, the Airports inquiries, and in the two water reviews in 2000.[8]

16.41 In this case we considered that, given our expenditure projections, NIE could maintain a gearing ratio of approximately 50 per cent throughout the remainder of the price control period whilst paying dividends consistent with the cost of equity net of RPI.

[8] In the Mid Kent inquiry, initial gearing was reduced below the regulated company's actual level, for which projections showed rapid deterioration in financial ratios.

Index-linked debt

16.42 We consider that a potential option available to regulated utilities wishing to improve interest cover ratios is to raise index-linked debt. We have not included index-linked debt in our modelling assumptions, but consider that it could represent a possible option for NIE.

Constrain or defer dividends

16.43 We consider that constraining or deferring dividends over the price control period may be a realistic option for a stand-alone regulated company and would not be expected to affect the cost of capital providing shareholders expected to realize a return through capital growth.

No additional adjustment

16.44 Contrary to the UR, we have calculated financial ratios without making any adjustment for the treatment of any pension deficit costs. In other words, our measures of forecast earnings reflect all of the pension deficit contributions that NIE is scheduled to pay, rather than excluding that element which was deemed to have arisen from the early retirement of former NIE employees.

Provisional results of the modelling

16.45 The financial ratios estimated by our provisional modelling for the period from October 2014 (when our determination is assumed to come into effect) to September 2017 (the end of the price control period) are as follows:

- PMICR ranges between 1.25 and 1.5;
- FFO/interest ranges between 3.2 and 3.4;
- FFO/net debt ranges between 20 and 22 per cent; and
- gearing remains at approximately 50 per cent.

16.46 We recognize that NIE’s PMICR is a potential source of concern. In considering possible actions to address this concern, NIE has several options to reduce its interest charges. These may include reducing net debt by limiting dividends, using cash or loans to other group companies before new debt to fund investment, issuing index-linked debt, or raising finance in the form of equity or equity-like instruments.

16.47 Given this, and taking the ratios in the round, our provisional view is that our determination is consistent with NIE maintaining an investment grade credit rating.

17. The reporter and information transparency

Introduction

17.1 In its reference, the UR required us to determine (see Section 1):

> … whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences …

17.2 In this section we therefore consider whether additional requirements regarding the reporting, recording and monitoring of information should be added to NIE's licence (we note that with regard to the verification of data there is no suggestion that data recorded by NIE is inaccurate). In particular, we consider two specific issues. These are whether, for RP5:

(a) a reporter function (as proposed by the UR) should be introduced; and/or

(b) NIE should be required to produce and publish additional information about its business.

17.3 We consider each in turn.

The reporter

17.4 In this subsection we consider whether a reporter function similar to that proposed by the UR should be introduced in RP5. It is structured as follows:

(a) We summarize the UR's proposal.

(b) We summarize NIE's arguments against introducing a reporter.

(c) We set out our provisional determination.

The UR's proposal to introduce a reporter

17.5 The UR said that the public interest required a significant improvement in the current levels of transparency and accountability in NIE's activities, not least due to the new substantial stakeholder interest due to increase renewable generation and market opening:

(a) because the quality and quantity of reporting from NIE on its regulated activities has not been adequate (for example, with regard to capitalization practices). It said that high-quality reporting and independent verification of data were essential even for a substantive capex programme of the current magnitude of RP4;

(b) due to the poor quality of NIE's business plan and failures of information submitted by NIE in the past in terms of transparency;

(c) because of the proposed substantial increase in capex over RP5 the need for high-quality reporting was even greater than it had been in the past; and

(d) because under its capex structure proposals those projects for which the necessity, timing or scale was not yet clear would be reconsidered and approved on an annual basis throughout RP5 (via Funds 2 and 3). This would clearly require constant communication and transparency between the UR and NIE throughout the price control period.[1]

17.6 It described the role of the reporter as having three limbs:[2]

(a) a technical role, auditing the outputs and unit costs of NIE's capex for the purposes of implementing the RP5 capex proposal, and advising the UR in relation to NIE's annual submissions for approval of further projects under capex Funds 2 and 3 in the following years;

[1] UR Statement of Case, UR-8, paragraphs 3–9.
[2] In the UR Terms of Reference for the Reporter, September 2012, paragraph 2.2, the areas of work are described as: Financial accounts; Capital expenditure reports; Capital expenditure database; RAB additions and disposals; Compliance Plan; Annual reporting requirements; Other regulatory submissions; special investigations.

(b) a financial role, reviewing NIE‘s accounting practices and advising the UR in relation to the same, so as to identify potential problems such as the capitalization practices issue referred to above before they arose; and

(c) a general ad-hoc role, investigating and reporting on any particular issues that we consider give rise to concern from time to time.

17.7 In addition, the UR envisaged that the reporter would play an important role with regard to its assessment during RP5 of projects where the necessity, timing or scale was not yet clear. The UR proposed that these projects should be reconsidered and approved on an annual basis throughout RP5. It submitted that this would require constant communication and transparency between it and NIE throughout the price control period. The reporter was a way of achieving this communication and transparency.[3]

17.8 The UR submitted that the introduction of a reporter did not add to its information-gathering powers (which it already had); but an independent, embedded (part-time) reporter would enhance its understanding of NIE’s business. It said that its proposals were less onerous than those required by Ofgem (under RIGs).

17.9 The UR said that the larger capital programme was not the trigger for introducing a reporter, only the reason to have a larger quantity of reporting. In its view, the factual background of this case required a step change in the quality of accountability and transparency: a reporter was a good way of achieving that.

17.10 It said that the reporter might not be deemed as the perfect solution. Instead it was an essential step in the move towards more effective regulation. During its development of this policy, it identified both pros and cons with this approach. However, in its

[3] UR Statement of Case, UR-8, paragraph 9.

judgement (and based on its experience of the transition that it facilitated in Northern Ireland Water), this solution would be most effective method of ensuring the transparency and accountability that all stakeholders required going forward.

NIE's arguments against a reporter

17.11 NIE said that the UR's proposed reporter would be considerably more 'hands-on' than the reporters in the previous Ofwat regime.[4] In NIE's view, a reporter was unnecessary and much of the role would not be required if we adopted the traditional approach to regulating capex.[5]

17.12 NIE said that a reporter would be a further step towards a regulatory model that tended towards micro-management and it would create uncertainty as to whether NIE or the reporter was responsible for decision making.[6] That is, there were unanswered questions around the reporter's accountability, its uncertain legal status (eg if the UR were effectively to delegate some of its functions to the reporter), and NIE's right of redress etc (eg if the UR were to base its regulatory decision on findings made by the reporter which NIE considered to be erroneous).[7]

17.13 With regard to the remainder of the role (for example, validating information, capex reporting, regulatory submission), NIE said that a reporter was no substitute for clear rules and reporting arrangements and NIE would work with the UR to meet its increased reporting requirements.[8] NIE said that it would strongly support establishing a Northern Ireland equivalent to Ofgem's RIGs (eg to facilitate benchmarking

[4] NIE Statement of Case, Chapter 14, paragraphs 2.5 & 2.6.
[5] ibid, Chapter 14, p327.
[6] ibid, Chapter 14, paragraphs 2.1–2.2 & 2.7.
[7] Cover letter to NIE's Statement of Case, 10 May 2013, paragraph 15.
[8] NIE Statement of Case, Chapter 14, p327, and NIE Supplementary Submission, Annex 12, paragraph 2.2.

against the DNOs) and confirmed its commitment to working with the UR to develop further output measures (in the form of load and health indices).[9]

17.14 Finally, it considered that the total cost of embedding a reporter would be significantly higher than the UR's cost estimate of £1.5 million over RP5 due to servicing the needs of the reporter.

Our provisional conclusion on the reporter

17.15 We considered the submissions of both parties, in addition to the third party submissions which were made on this issue (these are summarized in Appendix 17.1).

17.16 With regard to the current data reporting arrangements, we found that NIE's current reporting structure made comparisons and benchmarking against its closest comparators, the GB DNOs, a lengthy and difficult exercise (see Section 8). The current reporting structure also made it difficult to estimate the direct-cost element of Core Network Investment. As a result, it is difficult to compare easily NIE's unit costs for network investment to the GB DNOs. We also found that the classification of costs between NIE and Powerteam made NIE's cost structure more complex and difficult to understand easily (see Section 8). In our view, enabling a clearer understanding of NIE's costs and better comparability of its performance against the GB DNOs is important and is in the public interest.

17.17 We therefore judged that NIE's current data reporting needed to be improved and we decided that a step change in data transparency was required. In our view, an increase in the quality of standardized data reporting which also enables NIE to be compared with its peers is a priority and in the public interest. This is because it will

[9] NIE Supplementary Submission, Annex 12, paragraphs 3.18 & 3.21.

provide all stakeholders with more transparency and greater confidence about how NIE is performing.

17.18 We were not convinced that the introduction of a reporter was the best way to achieve our aim of greater data transparency. In particular, we were concerned that the introduction of a reporter, as envisaged by the UR, would potentially involve significant amounts of investigatory work rather than auditing/verification of data. For example, the UR proposed that the embedded reporter should review and advise on accounting practices.

17.19 We provisionally decided that greater data transparency would be best achieved through the publication of more useful data which has been prepared according to clearly-defined rules. The UR, through its existing powers, would be able to audit and verify this data as it considered appropriate.

17.20 The UR also proposed that the reporter would advise it on assessing projects (see paragraph 17.7). Our price control design will require some project assessment by the UR during RP5 (see Section 5). We therefore considered whether a reporter would be a valuable additional resource in this process. We found that this was unlikely to be the case because the UR can employ its own consultants to review projects in a very similar way as a reporter would (as it did with SKM for RP5). We judged that the additional benefits which an embedded reporter might bring over a consultant employed by the UR were small and would be significantly outweighed by the risk that the reporter became seen as a decision maker.

17.21 For the reasons outlined in paragraphs 17.16 to 17.20 above, our preferred approach to transparency is to focus on significantly increasing the amount of useful and comparable data which NIE produces. We believe that this should address the issues of data transparency which we have identified as being against the public interest (see paragraphs 17.16 and 17.17). We believe that this approach will achieve much of what the UR aimed to achieve with the introduction of a reporter, but without the aspects of this arrangement which concerned us (see paragraphs 17.18 and 17.20).

17.22 We believe that as far as is possible any additionally reported data should be made publicly available. We discuss our proposals for increasing the quality of data reporting in the next section.

Increased reporting

17.23 In this section, we explain our proposals for increasing the quality of data reporting in RP5. We begin by summarizing the views of the parties before explaining our provisional determination in this area.

The parties' views of regulatory reporting

17.24 The parties seemed to be broadly in agreement that additional regulatory reporting would be beneficial.

17.25 NIE told us that there was a perception that transparency could be improved and that this could be helped by increased reporting: it said that it wanted to engage on this issue. It told us that any requirements should be specified as clearly as possible, as early as possible, so that it could start to work to put the necessary processes and systems in place.

17.26 NIE also told us that one of the things that the increased reporting should do was facilitate benchmarking of NIE against the GB DNOs, because they were the most relevant comparators. It said that trying to get NIE's cost reporting on a basis which was similar to GB was a sensible approach and it thought that this would also appeal to the UR.

17.27 NIE told us that the UR had already asked for its views on a pro forma of reporting metrics that could be used.

17.28 The UR expressed concern about the level of transparency and accountability in NIE's operations. It said that effective reporting was an essential prerequisite for effective regulation and so it had proposed measures to improve the quantity and quality of information that it collected from NIE.[10]

17.29 The UR told us that it wanted additional reporting beyond what had been provided in RP4. It said that for benchmarking purposes NIE should report on the same basis as the GB DNOs. It told us that the regular annual reports currently available did not provide anywhere near the equivalent level of detail to the GB DNOs and that there was nothing which could be used to benchmark NIE against the GB DNOs.

17.30 The UR said that its benchmarking was based on the price control submission and not the annual reports. It said that the amount of cost mapping required and the errors that have been uncovered through our process means that it would not be sustainable to review and repeat this exercise every year.

17.31 The UR told us that if we decided that the Ofgem reporting standards (the RIGs) should be adopted, then this would make it easier to analyse and benchmark NIE. It said that the reason it had decided against this was because of concerns about the burden it would put on the company: the Ofgem RIGs were very extensive. It therefore thought that a reporter was more appropriate.

[10] UR Statement of Case, UR-2, paragraph 3.

Our provisional proposal on regulatory reporting

17.32 We believe that increasing the quantity and quality of data reporting is in the public interest. There two very significant benefits from better data reporting:

(a) it will improve the level of transparency of NIE's business for both the UR and other stakeholders. The need for more transparency has been repeatedly mentioned by the UR and by third parties; NIE also recognized that there would be benefits from increased transparency.

(b) it will make comparison of NIE's performance with the GB DNOs much easier. Being able to assess the performance of a regulated business against comparable companies' should improve regulatory outcomes. For example, comparing NIE's volumes, direct unit costs and indirect costs with the GB DNOs will provide the UR with important information in setting its next price control. We have found that NIE's current reporting makes these comparisons a lengthy and difficult exercise.

17.33 We considered that the Ofgem RIGs for the GB DNOs were the logical starting point for any new reporting requirements. These are the standardized annual data reporting requirements which the GB DNOs produce. The RIGs would cover a very significant proportion of NIE's network (although not the 275 kV network) and both parties agreed that the GB DNOs represent the most appropriate comparators for performance. In addition, Ofgem has worked for a number of years to develop and refine its rules on data collection; adopting the RIGs would allow all stakeholders to benefit from a system which is robust and which has been in place for several years.

17.34 We recognized that in order for increased reporting to work well and deliver significant benefits to stakeholders, the UR would have to have the capacity to process any additional data. We noted that Ofgem has available to it significantly greater resources (and economies of scale) than the UR. However, the UR said that it would be content to adopt the RIGs system and we had no reason to believe that it would not be able to process the additional data effectively.

17.35 We have used benchmarking extensively in setting our cost allowances (see Sections 7 and 8). One of the main benefits we identified from increased data reporting is the ability to make benchmarking exercises easier in future. It will allow NIE's cost performance to be assessed and cost allowances set which are independent of the historic costs of NIE. However, for this to be effective it is important that the UR can access the relevant GB DNO data sets from Ofgem (in some form). Our experience in this inquiry provided us with some comfort that the UR would be able to access relevant GB DNO data in future charge controls.

17.36 We therefore decided to provisionally determine that a requirement to deliver increased regulatory reporting based on the RIGs should be specified as a licence condition.

17.37 We also considered whether we should include a licence condition requiring the independent verification of this data by a suitable third party (for example, an auditor). We decided that requiring director sign-off of the regulatory reporting data would add sufficient assurance of its accuracy.

17.38 We considered specifying ourselves which of the RIGs NIE should be required to complete in the licence. We decided that this was not the best approach because the regulatory benefit of increased reporting would fall in RP6 and subsequent price controls; it therefore made more sense for the UR (in consultation with NIE) to specify exactly which of the RIGs would be most useful to it.

17.39 We therefore provisionally determined that a new licence condition would be created which required NIE to complete the full DNO RIGs, with the UR granting exemptions for those elements which it considered were either not relevant or not useful.

17.40 Additionally, we proposed that NIE would be able to apply to the UR, with reasons, for an exemption if it considers that the elements would not be useful. The UR would then be required to evaluate whether an exemption should be granted. We provisionally determined that NIE be required to report under this structure for the year ended September 2014 first. This first reporting year would be on a best endeavours basis, allowing for complete reporting for the year ending September 2015.

17.41 We put this proposal to the parties before the publication of our provisional determination. We summarize below their responses.

The parties' response

17.42 The UR said that it was content to adopt the RIGs system, depending on the price control design. It also said that costs would need to be prepared 'like for like' since NIE had some different responsibilities from the GB DNOs (for example, metering); separate information would also be required for the 275 kV network.

17.43 NIE said that it could be required to produce a large amount of nugatory work. It said that the UR would require additional resources and it expressed concern about whether the required exemptions would be granted by the UR on a timely basis: if no exemptions were granted by the UR, it would have a very onerous task completing some RIGs which would be of no use to the UR, stakeholders or customers.

17.44 NIE considered that the initially proposed timeline (completion of agreed RIGs on a best endeavours basis for the year to September 2014) was not achievable. It noted that ongoing engagement was required when Ofgem first introduced the RIGs in GB.

17.45 NIE said that the cost in GB was 15 person months per group. It said that scoping out the full RIG requirements and aligning the various cost collection processes and IT systems within NIE to these agreed RIGs would require a large body of work.

17.46 NIE instead proposed that the UR engage with NIE to agree an appropriate set of Northern Ireland RIGs using Ofgem definitions and templates to ensure transparency and allow benchmarking to take place. It said that this would be a more efficient process and would benefit future price controls.

Our view

17.47 We did not consider that the cost stated by NIE (15 person months) was high relative to the very significant public interest benefits which we would expect to arise from increased reporting.

17.48 We do not consider that our provisional determination would require the preparation of a large amount of nugatory work. We recognize that there are differences between NIE's responsibilities and that of the GB DNOs; that the regulatory regimes in GB and Northern Ireland are different in some ways; and that as a result aspects of the Ofgem RIGs are clearly not relevant to NIE.

17.49 It was for this reason that we provisionally determined that the UR be able to grant exemptions for those aspects of the RIGs which are not relevant or useful. As an additional protection against NIE being required to complete unnecessary work, we also provisionally determined that NIE be able to apply to the UR for exemptions from those aspects of the RIGs which are not relevant or useful. We have no reason to believe that valid exemptions requested by NIE would not be agreed by the UR on a timely basis.

17.50 We recognized that in the first year reporting would be on a best endeavours basis. Indeed we would envisage that a number of additional exemptions may be necessary in the first year as the new system gets up and running.

17.51 In our view, synchronizing the reporting year end with Ofgem would make sense. In addition, we have considered NIE's comments on timeline. As a consequence, we provisionally decided to adjust the date when NIE would be required to report first under this system (on a best endeavours basis) to the year ending March 2015 (it had been September 2014 in our proposal to the parties).

17.52 This would allow for one year of reporting (April 2014 to March 2015) before the 2015/16 reporting year, which is likely to be the base year for next price control. We believe that the availability of a suitable set of RIGs reporting data for this base year is very important and would provide a significant benefit for the RP6 price control.

17.53 In addition, we have asked the parties to identify which of the RIGs they consider would be either irrelevant or not proportionate to complete during RP5.[11] We have asked them to distinguish between those which they consider are irrelevant and those which they consider are not proportionate. This may enable us to identify, as part of the new licence condition, a number of RIGs which NIE are not required to complete.

[11] The deadline for responses to this and other questions is 15 November 2013.

17.54 We believe that, as far as is possible, any additional data produced by NIE should be made publicly available. We therefore asked the parties to identify, with reasons, which of the remaining RIGs (ie those that would be completed by NIE) should not be published.

17.55 We recognized that our initial proposal did not define any separate reporting requirements with regard to NIE's Transmission network. We therefore asked the parties for their views on how best to capture NIE's Transmission business within any new reporting requirements, including (but not limited to):

(a) which (if any) of the Ofgem Transmission RIGs should be included in any new reporting requirements;

(b) whether Transmission reporting would be best limited to the 275 kV network (with 110 kV captured by Distribution reporting); or whether it should also include the 110 kV network; and

(c) whether alternatively NIE should report the whole of its network (including the 275 kV network) under the Distribution RIGs.

17.56 We expect that the parties' response to this question will enable us to define additionally how NIE's Transmission network should be treated and captured within our proposed data reporting licence condition.

Conclusion on the reporter and overall transparency

17.57 We found that it would be in the public interest for there to be a step change in NIE's data reporting. We considered that this would bring significant benefits to stakeholders. For the reasons outlined in paragraphs 17.18 to 17.21, we provisionally decided that the introduction of a reporter function was not the best way to achieve this.

17.58 We provisionally decided that a licence condition should be added which required NIE to report against the Ofgem GB DNO RIGs, with a mechanism added (see paragraphs 17.39 and 17.40) that would ensure that only those RIGs relevant and useful to stakeholders were required. We provisionally decided that NIE would be first required to report under this system, on a best endeavours basis, for the year ending March 2015. We provisionally decided against requiring any independent verification of this data; instead it will be subject to director sign-off by NIE.

17.59 We have consulted with the parties on a number of issues raised by our initial proposal, including: making specific RIG exclusions in the licence condition; publication of the data; and how to best capture NIE's Transmission business. The parties' responses may enable us further to refine our proposal in these areas by the time of our final determination.

18. Findings

18.1 In this section we state our provisional findings on the public interest and set out our provisional determination.

RP4 and the public interest

18.2 The UR's reference to the CC required us to consider whether the Price Control Conditions in each Licence operate or may be expected to operate against the public interest.

18.3 Article 15(7) of the Electricity Order provides that, in determining whether any particular matter operates, or may be expected to operate, against the public interest, the CC must have regard to the matters as respects which duties are imposed on the UR by Article 12 of the Energy Order or Article 9 of the SEM Order (see paragraph 1.12). We have applied the public interest test with due regard to these duties.

18.4 For the reasons set out in paragraphs 3.58 to 3.73, we find that aspects of the existing Price Control Conditions operate against the public interest.[1] The reasons for finding that aspects operate against the public interest are, in summary:

(a) application of the current Price Control Conditions generates uncertainty for NIE, its investors, its customers, the UR and other stakeholders;

(b) aspects of the price control design are not sufficient to protect the interests of consumers;

(c) the current Price Control Conditions allow an excessive cost of capital; and

(d) the duration of the RAB for short-lived assets (ie tree cutting) operates against the interest of future customers.

[1] Our findings in relation to the second of the UR's questions are set out in paragraphs 18.44–18.46.

18.5 We note that the UR and NIE were agreed that the existing price control conditions operate against the public interest.

Modifications to the licence conditions

18.6 The UR's reference also requires us to answer 'whether the effects adverse to the public interest which those matters have or may be expected to have could be remedied or prevented by modifications of the Conditions of each Licence'. We now set out our findings in relation to aspects of the price control and our provisional determination of modifications to the licence conditions. The overall allowed revenues are set out in Table 18.1, and opex and capex allowances are set out in Tables 18.2 and 18.3.

Design of price control

18.7 For the reasons set out in Section 5 of this report, we provisionally determined that significant changes to the design of the price control will address the effects adverse to the public interest. Our provisional determination for alterations to the licence conditions, while still an example of RAB-based incentive regulation, also differs substantially in several respects from the arrangements proposed by the UR in its RP5 determination document.

18.8 Our provisional determination with regard to the price control design is set out in paragraphs 18.10 to 18.29.

18.9 We have also provisionally determined that there should be separate revenue controls for transmission and distribution, in line with the separate Licences (see paragraphs 5.15 to 5.17). Apart from consistency with the separation of licences, separate revenue controls can help better align transmission charges with transmission costs and distribution charges with distribution costs.

Cost risk-sharing mechanism

18.10 We have provisionally determined a new price control for NIE calculated by reference to our assessment of NIE's expenditure requirements (if it were to operate efficiently) in the period from 1 April 2012 to 30 September 2017. We have provisionally determined that the price control should include arrangements that have the effect of sharing between consumers and NIE's investors the differences between our assessment of NIE's expenditure requirements and NIE's out-turn expenditure (see paragraphs 5.69 to 5.116). Our proposed approach provides some protection to consumers against the risks that our assessment overestimates NIE's expenditure requirements. It also provides some protection to NIE against the risk that our assessment underestimates NIE's expenditure requirements.

18.11 More specifically, we have proposed in our provisional determination a cost risk-sharing mechanism under which 50 per cent of any difference between our assessment of NIE's expenditure requirements and NIE's out-turn expenditure in a particular financial year is passed through to consumers through adjustments to NIE's maximum regulated revenue in subsequent years. The rate of 50 per cent will apply to NIE's opex and capex. In determining this mechanism we have sought to ensure that NIE will face clear and strong financial incentives to operate and invest efficiently and to avoid unnecessary expenditure. We have also sought to reduce the risk that the regulatory framework gives NIE financial incentives to favour unduly working practices and capitalization practices that inefficiently enhance NIE's capex relative to its opex.

18.12 The cost risk-sharing mechanism will not apply to elements of the new price control subject to full cost pass-through (eg licence fees) nor to costs for connection services funded by connection charges outside the scope of NIE's revenue control. It will be calculated by reference to NIE's out-turn costs excluding any profit margin that may be charged by NIE Powerteam to NIE.

Inefficient spend clause

18.13 We have provisionally included a provision within NIE's licence conditions that the UR can make adjustments to NIE's revenues or RAB to protect consumers from exposure to any costs that are demonstrably inefficient or wasteful (see paragraphs 5.117 to 5.132. This clause will apply across all areas of NIE's expenditure. In making any decision under this clause, it would be for the UR to determine that expenditure was demonstrably inefficient or wasteful.

Measures to tackle risk of deferral of planned network investment projects

18.14 Under conventional RAB-based incentive regulation, there is a risk that a regulated company may defer investment projects for which it has received an allowance, to the detriment of consumers. In particular, there is then a risk that the company would seek further allowances in subsequent price controls for similar projects, or for ones which are designed to have the same impact as those that have been deferred.

18.15 The approach we have provisionally determined (see paragraphs 5.133 to 5.224) is not to prevent investment deferral, some of which may be efficient, but rather to protect consumers from adverse financial consequences in the event of investment deferral. The approach would be based on an expectation that, at future price control reviews, the determination of NIE's maximum revenue and RAB by the UR could be done by reference to a policy that there should be no double funding of deferred network investment. Therefore, in subsequent price controls, we would expect that NIE would be required to identify any aspects of its forecast network investment which arise as a result of deferment or abandonment of investment that was included in the calculations we have used to set a new price control for NIE. These would be netted off its expenditure allowances for the subsequent price control period. This aspect of our provisional determination is intended to protect customers from the risk of facing charges for further work which has already been funded, as a result of deferment or abandonment of projects planned for RP5. While our determination cannot bind the UR in regard to how it regulates NIE in future price controls, our intention is to create a system which allows the UR to avoid double funding of deferred investments in future.

18.16 We are mindful that needs and priorities can develop over the course of a control period and that NIE's investment plan will change over time. Our proposed approach would still provide NIE with financial incentives to defer planned projects where it is efficient to do so and to abandon planned projects that are no longer necessary.

Investment projects for distribution network-load-related expenditure

18.17 There is uncertainty about NIE's expenditure requirements for work to increase the capacity of its distribution network over the next few years. We considered possible mechanisms or provisions in the price control framework to allow some flexibility to reflect changes in requirements in the period to 30 September 2017 (see paragraphs 5.224 to 5.249).

18.18 We considered proposals made by the UR which would involve NIE seeking approval for new investment projects on the distribution network as the needs arise. We found that these proposals would involve a degree of regulatory micro-management in NIE's business and would increase the regulatory burden. We did not consider these proposals to be a proportionate response to the scale of uncertainty in NIE's expenditure requirements. We also considered an option that would allow NIE's maximum regulated revenue and RAB to adjust mechanistically according to the investments it carries to increase distribution network capacity, subject to its investment decisions being compatible with approved asset management documentation. Such an approach would provide more flexibility to NIE than the UR's proposals. However, we identified practical impediments relating to the agreement of asset management documentation and establishment of an effective revenue-adjustment mechanism based on upfront unit cost estimates.

18.19 In view of the relative scale of expenditure envisaged by NIE and the drawbacks we identified (and that we are already minded to allow certain projects (see paragraphs 18.34 and 18.35), we have provisionally determined not to use any of the adjustment mechanisms or provisions we considered. Instead, we propose to set an upfront allowance in relation to distribution-load-related expenditure, with the same cost risk-sharing arrangements as for other areas of NIE's expenditure.

Investment projects to increase transmission system capacity

18.20 There is also substantial uncertainty about the investment that NIE will need to carry out to increase the capacity and capabilities of its transmission network (eg to help accommodate further renewable generation). We have provisionally determined (see paragraphs 5.250 to 5.269) that there should be provisions within NIE's licence conditions to allow the UR to make within-period adjustment to NIE's revenue restriction and RAB calculations, to allow funding for new investment projects to increase the capacity and capabilities of the transmission network (for projects not included as part of the cost assessment we have used for our determination). NIE will be able to apply to the UR on a project-by-project basis for an increased allowance during the price control period, without having to wait for the UR's next price control review. The same cost risk-sharing arrangements apply as for other projects based on the UR's appraisal of the upfront cost allowance.

18.21 While not part of our provisional determination on modifications to NIE's price control conditions, we also recommend that the UR considers, where appropriate, the opportunities for enabling a greater role for competition in the development, ownership and maintenance of new investments to increase transmission network capacity. The anticipated transfer of NIE's transmission planning responsibilities to SONI from April 2014 is likely to increase such opportunities.

Electricity meter investment and smart meter programme

18.22 Our provisional determination is that a form of volume driver mechanism is appropriate for NIE's capex in relation to electricity meters (see paragraphs 5.274 to 5.287). We have made upfront forecasts of NIE's capex on electricity meters, but the revenue restriction in NIE's licence conditions will adjust mechanistically according to the out-turn volumes of metering investments that NIE carries out. The adjustment will be calculated by reference to unit cost allowances for different categories of metering capex. This mechanism helps address substantial uncertainty about the volumes of metering investment that NIE will need to carry out.

18.23 The mechanism we have provisionally determined for metering capex is focused on conventional electricity meters (including keypad meters) and is not intended to accommodate a potential future transition to smart meters. If the smart meter programme in Northern Ireland means that changes are needed to NIE's maximum regulated revenue before 30 September 2017, we would expect the UR and NIE to make use of either the change of law provision in the existing licence conditions (which we propose to retain) or a licence modification.

Pass-through of specified connection costs

18.24 NIE imposes charges for new connections to its network (also known as customer contributions). These are subject to price regulation outside of the NIE revenue control that is the main subject of our inquiry. At present there is an arrangement by which an element of certain connection charges is 'subsidized' through NIE's RAB and revenue control, rather than falling entirely on the party seeking the new connection. Our provisional determination is that costs relating to this subsidy from NIE's RAB should be recovered on a cost pass-through basis (see paragraphs 5.288 to 5.297). This will be a temporary arrangement until 1 October 2014 as the UR has made a regulatory policy decision to terminate the current subsidy from the RAB from that date. Any costs incurred after that date will not be recoverable through NIE's RAB.

Pass-through of specified operating costs

18.25 Under RP4, certain operating costs that NIE incurs are passed through, in full, to consumers. These relate to: the regulatory licence fees that NIE pays; wayleave costs; and rates (forms of taxation on NIE's premises and assets)—see paragraphs 5.298 to 5.349.

18.26 Our provisional determination is that licence fees should be treated as a cost pass-through item. However, rates and wayleaves should not be subject to cost pass-through. Instead an upfront allowance and the cost risk-sharing mechanism described above will apply.

18.27 We propose that there would be no upfront allowance for costs relating to injurious affection but there should be a provision for the UR to make an allowance in the future. This would be informed by the results of a forthcoming Lands Tribunal determination.

18.28 NIE had proposed that its costs relating to rates, wayleaves and injurious affection should be recoverable in full from charges to consumers. We consider that such an arrangement could expose consumers to unnecessarily high costs as NIE would have no financial exposure to the level of costs that it incurs in these areas and therefore no incentive to try to reduce these costs.

Other terms to remove from current licence conditions

18.29 We have provisionally proposed (see paragraphs 5.350 to 5.358) the removal from the Price Control Conditions of various elements which we consider to be redundant following changes to the Licences under the other modifications we have provisionally determined.

Quality of service and other incentives

18.30 We considered various proposals relating to the regulation of NIE’s quality of service or output through NIE’s price control conditions, covering: guaranteed standards; customer interruptions; and electrical losses incentives (see paragraphs 6.1 to 6.14). We took account of the parties’ proposals, information on the quality of NIE’s existing services and NIE’s statutory obligations. We have not proposed any such schemes in the provisional determination. The UR and NIE proposed the introduction of a financial incentive scheme concerning the number and duration of interruptions to customers’ electricity supplies, but disputed several important aspects of the design and calibration of such a scheme. We found that a poorly designed scheme could be worse than no scheme and could impose unnecessary costs on consumers. We have not found that the absence of such a financial incentive scheme operates against the public interest and have not included the introduction of such a scheme in our provisional determination. Instead, we propose that NIE publishes its annual performance in terms of measures of customer interruptions and explains any shortfalls in performance against its forecasts.

18.31 We propose changes to the treatment of income that NIE receives as part of revenue protection activities (eg revenue recovered in cases of illegal abstraction of electricity)—see paragraphs 6.15 to 6.20. We propose that 50 per cent of the revenues that NIE receives each year should be shared with consumers by offsetting them against NIE's maximum regulated revenue in a subsequent financial year. This widens the scope of a similar arrangement applying to money recovered by NIE in relation to vacant non-domestic premises.

Allowance for indirect costs, inspection, maintenance, faults and tree-cutting

18.32 We have made a provisional determination of an annual allowance for NIE's indirect costs and costs for inspection, maintenance, faults and tree cutting (IMF&T) using the results from benchmarking analysis of the costs of NIE and 14 GB DNOs (see Section 8).

18.33 These categories both include costs that are capitalized and costs that are not capitalized. Our benchmarking analysis therefore cuts across NIE's capex and its opex. Because we maintain the approach of including forecast capex in NIE's RAB, we need to separate our allowance for indirect and IMF&T costs between opex and capex. We have done this by applying an allocation based on the separation of NIE's historic indirect and IMF&T costs between opex and capex.

Core network investment

18.34 We have proposed an allowance for NIE's core network investment expenditure (see Section 9). We employed engineering consultants (BPI) to assess NIE's project by project submissions in this area. We focused mainly on those projects where the greatest differences existed between the UR's final determination and NIE's submission. Our allowance for RP5 was based on those projects which BPI assessed had been included in NIE's plan with sufficient justification. We carefully reviewed

BPI's recommendations (the UR and NIE also provided substantive responses) and we required BPI to develop its recommendations or undertake further work where appropriate, and we made further adjustments (eg for indirect costs) before we reached a provisional decision. Our provisional determination therefore included all projects which, in our judgement, it would be sensible for NIE to complete in RP5.

18.35 We gave additional review to three projects which, for a variety of reasons, stood out to us as requiring additional scrutiny. We concluded that some additional provision should be made for work to ensure NIE's compliance with ESQCR requirements. We were not persuaded that a large-scale pilot to accelerate network resilience work to deal with ice accretion was well justified or demonstrably cost effective; nor was an 11 kV network performance project to install remote control facilities. We made an allowance for non-recoverable alterations and we removed a project relating to Road and Street Works legislation which is not currently predicted to have any impact in the relevant period. We also made an adjustment to remove indirect costs to enable us to set a direct-only core network investment allowance. Finally, we adjusted our forecast to allow for the length we now propose for the RP5 period.

Other elements of cost assessments

18.36 We provisionally determined allowances for a variety of other specific items (see Section 10). This includes items to be recompensed on a cost-pass through basis (eg capital cost of new connections and licence fees). Other items where we have made specific separate allowances include the cost of the Enduring Solution market opening project; non-network capex; metering capex; additional opex costs relating to ESQCR; storm costs relating to atypical severe weather; meter reading and operating costs related to keypad meters; rates; injurious affection; and others.

RPEs and productivity

18.37 We made a forecast of how NIE's costs may compare with expected changes in general inflation (measured by the RPI) over the period. This is because NIE's allowed revenues are indexed to increases in RPI but the costs of an efficient firm might be expected to follow a different path due to the combined effects of productivity and RPEs. We have adapted allowances accordingly. We estimated productivity improvements at 1 per cent a year for each of opex and capex. We estimated RPEs for the period. We provisionally determined that the combined effects of our productivity and RPEs forecasts should apply from the base year of the price control (2009/10). This analysis is set out in Section 11.

Pensions

18.38 We examined a variety of issues around pensions. We provisionally determined (see paragraph 12.55) that only the pension schemes which provide services exclusively to the regulated business of NIE should be included in our revenue control. We also provisionally determined that the deficits in the included schemes should be split into historic (up to 31 March 2012) and incremental deficits. The historic deficit will be funded 100 per cent by consumers, with the deficit recovered over a period of 15 years; any incremental deficit arising will be funded 100 per cent by NIE. Deficit repair payments should be reviewed (and changed if necessary) following each triennial valuation. We provisionally determined that NIE should be refunded its stranded pension costs from RP4 over a period of 15 years and also that the current split of ERDC liabilities should be retained. We determined that no adjustment to NIE's ERDC liability should be made for previous shareholder contributions.

18.39 NIE's ongoing pension service costs are included in our indirect benchmarking and therefore no additional allowance is included for this item.

Allowed rate of return

18.40 We examined the return that NIE should be allowed to earn on the RAB (see Section 13). We considered that this should be set equal to the expected cost of capital for NIE as if it were a stand-alone company. We provisionally determined that NIE's real WACC for RP5 is 4.1 per cent.

Unresolved RP4 issues

18.41 NIE drew our attention to certain outstanding issues with respect to the RP4 period. Our investigation into these matters showed that these were aspects relating to the implementation of RP4. Therefore we provisionally determined (see paragraphs 14.19 to 14.28) that these did not call for further investigation or for any adjustments for the purpose of the next price control.

Capitalization practices

18.42 The UR asked us to investigate whether changes in NIE's capitalization practices meant that, in effect, customers had paid twice for certain activities in RP4. It suggested this might have arisen because the activities had been funded through both an opex allowance and capex allowance, when NIE had changed its accounting treatment of certain activities from opex to capex. It considered that changes in capitalization practices might have contributed to apparently high levels of opex outperformance achieved by NIE in RP4. Our considerations are set out in Section 15. We concluded that the design of the RP4 price control could incentivize NIE to recategorize opex as capex in this way, because opex allowances were based on historic opex levels whereas capex was remunerated on a pass-through basis. We concluded that the RP4 price control was against the public interest because this could distort NIE's choices between opex and capex and lead to NIE receiving inappropriate opex allowances.

18.43 However, on examining the facts, we were not convinced that NIE had engaged in reclassification of activities in this way to a significant extent. Changes in the balance of opex and capex activities reflected a mix of causes, including genuinely additional capex activities, the replacement of reactive opex with planned programmes of capitalizable activities, and improvements in information allowing replacement of assets to be better planned and better recorded. In addition, NIE will have achieved genuine opex efficiency improvements. We noted that the opex allowance in RP4 was never explicitly allocated to particular expenditures. Instead, NIE was incentivized to outperform on an overall opex allowance. We were satisfied that reasons other than simple recategorization of opex to capex accounted for at least a substantial part of the recorded outperformance and there was not a practical method to isolate any recorded opex outperformance arising specifically from recategorization. We also thought that any intervention to correct for such effects after the period in which the regulatory design applied could be harmful to investors' perceptions of regulatory stability. We provisionally determined to make no correction to opex outperformance in RP4.

Regulatory reporting

18.44 In its reference, the UR required us to determine:

> … whether the continuation of each Licence operates or may be expected to operate against the public interest absent the inclusion of further conditions designed to improve the recording, reporting, monitoring and verification of information related to the Price Control Conditions and related conditions of the Licences …

18.45 As noted in paragraphs 17.57 and 17.58, we provisionally determined that the current arrangements were not in the public interest. We provisionally found that a step change in data reporting would bring significant benefits to stakeholders. However, we provisionally determined that the introduction of a reporter function was not the best way to achieve this.

18.46 We provisionally determined that a licence condition should be added which required NIE to report against the Ofgem GB DNO RIGs, with a mechanism added that would ensure that only those RIGs relevant and useful to stakeholders were required. We provisionally determined that NIE would be first required to report under this system, on a best endeavours basis, for the year ending March 2015.

RAB for short-lived assets

18.47 For the reasons set out in paragraphs 15.88 to 15.92, we have provisionally determined that a new five-year RAB should be adopted for all new capitalized tree cutting undertaken from the start of the RP5 period. We have also found that investments in certain IT under the non-network capex category should similarly now be put into a five-year RAB.

Timing and duration of price control

18.48 For the reasons set out in Section 4, we propose that the new price control governs the calculation of tariffs applicable from 1 October 2014 onwards. However, we provisionally determined that the price control should have the effect of also setting NIE's maximum regulated revenue in the period between 1 April 2012 and 30 September 2014. Therefore we have set out as part of the calculation of the new price control from 1 October 2014 arrangements to provide some compensation to consumers or NIE in relation to deficiencies in the calculation of NIE's maximum regulated revenue arising from the fact that tariffs have already been set for the period between 1 April 2012 and 30 September 2014.

18.49 We propose that the new price control should have a planned end date of 30 September 2017.

18.50 We considered it prudent to ensure that there were arrangements in place to ensure that some form of price control applies to NIE after the planned end date, in case of a failure to implement a new price control in time. To guard against this, we propose (see paragraphs 4.45 to 4.51) licence modifications with the effect that, in the period from 1 October 2017, the restriction on NIE's maximum regulated revenue is replaced with a restriction of no increases from the tariffs set from 1 October 2016.

Overall allowances in our provisional determination

18.51 Our provisional determination of NIE's allowed revenues are set out in Table 18.1, for each period from April 2012 to September 2017, expressed in constant 2009 prices. We have presented our provisional revenue allowances separately in respect of transmission and distribution, reflecting our provisional decision that each should be subject to separate revenue control. Our total allowed revenues over 5.5 years are £1,009 million, of which £846 million relate to distribution and £163 million to transmission.

TABLE 18.1 **CC provisional determination: estimated revenue allowances**

£ million (constant 2009 prices)

Start of period	*Apr 2012*	*Oct 2012*	*Jan 2013*	*Oct 2013*	*Oct 2014*	*Oct 2015*	*Oct 2016*	*Aggregate*
End of period	*Sep 2012*	*Dec 2012*	*Sep 2013*	*Sep 2014*	*Sep 2015*	*Sep 2016*	*Sep 2017*	
Our allowed revenues for transmission (2009/10)	13	6	21	28	30	31	33	163
Our allowed revenues for distribution (2009/10)	86	45	119	157	144	148	146	846
Our allowed revenues (2009/10)	99	51	140	186	174	180	180	1,009
Duration of period	6 mths	3 mths	9 mths	1 year	1 year	1 year	1 year	5.5 years

Source: CC calculations.

18.52 In Tables 18.2 and 18.3 (these are identical to Tables 7.4 and 7.5), we set out capex used to calculate additions to NIE's RAB and for opex. The figures below are calculated after the application of adjustments for productivity and RPEs (see Section 11). Total capex allowances in our decision for the period from April 2012 to September 2017 are £457.3 million. The total opex allowances for the same period are £261.5 million.

TABLE 18.2 **Summary table: capex allowances after adjustment for RPEs and productivity**

£ million (constant 2009 prices)

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Network investment direct costs:						
Distribution RAB	23.0	29.2	36.2	36.1	35.8	17.8
Transmission RAB	3.1	5.7	23.6	23.5	23.3	11.6
Benchmarked allowance for capitalized costs:						
Indirect & IMF&T costs (excluding tree cutting)	19.6	19.4	19.4	19.3	19.1	9.5
Tree cutting: distribution RAB	4.6	4.6	4.6	4.6	4.5	2.3
Tree cutting: transmission RAB	0.2	0.2	0.2	0.2	0.2	0.1
Non-network capex—five-year RAB	1.4	3.8	3.5	3.5	3.5	1.7
Metering capex:						
Distribution RAB	1.5	1.5	2.5	2.5	2.5	1.2
Keypad RAB	1.7	1.7	4.2	4.2	4.2	2.1
Allocation of overheads to distribution RAB	0.1	0.1	0.1	0.1	0.1	0.0
Allocation of overheads to keypad RAB	0.1	0.1	0.1	0.1	0.1	0.1
Connection charges funded through distribution RAB	4.8	2.4	0.8	-	-	-
Total	60.1	68.5	95.1	94.0	93.2	46.4

Source: CC analysis (rounded). See Table 7.4.

TABLE 18.3 **Summary table: opex after RPEs and productivity**

£ million (constant 2009 prices)

	Years ending					
	March 2013	*March 2014*	*March 2015*	*March 2016*	*March 2017*	*6 months to Sep 2017*
Operating expenditure subject to RPEs and productivity	34.3	33.9	33.6	33.2	32.8	16.3
Items not subject to RPEs and productivity:						
Rates	12.6	12.7	12.7	12.8	12.9	6.5
Licence fees	1.9	1.9	1.9	1.9	1.9	1.0
Deduction: connection charge contribution to O&M	–0.6	–0.6	–0.6	–0.6	–0.6	–0.3
Total	48.2	47.9	47.6	47.3	47.0	23.5

Source: CC analysis (rounded). See Table 7.5.

Financeability

18.53 The regulator has a duty to secure that licence holders are able to finance their activities which are the subject of obligations imposed under statute. Based on our preliminary modelling (see paragraphs 16.45 to 16.47), our provisional view is that our determination is consistent with NIE maintaining an investment grade credit rating.

18.54 However, we recognize that NIE’s interest cover ratio is a potential source of concern. In considering possible actions to address this concern, NIE has several options. These may include limiting dividends, converting any non-regulated assets into cash, the issuance of index-linked debt to reduce cash interest expenses, and raising of finance in the form of equity or equity-like instruments (ie an equity injection).

Implications of our findings for customers

18.55 We now set out our expectations as to the effect our provisional determination would have on customers.

18.56 Our determination will set NIE’s maximum allowed revenues for distribution and transmission use of system charges. It will not set directly the distribution and transmission tariffs that NIE charges to SONI and energy retailers, or any of the prices charged by energy retailers to customers. NIE’s distribution and transmission tariffs are subject to separate approval by the UR. We have assumed that tariffs are adjusted pro rata to changes in allowed revenues.

18.57 We have used the UR’s financial model to estimate the impact of our provisional determination on allowed revenues. However, we also need to deal with the effect of past under- or over-recoveries of revenue between April 2012 and September 2014. Factoring in past under-recoveries will affect the revenues NIE can raise, and so how tariffs develop.

18.58 We set out in Table 18.4 our allowed revenues for each year (these figures are for transmission and distribution combined), and how these compare to the recovered revenues between April 2012 and September 2014 (whereafter tariffs can be adjusted). The table sets out our provisional illustrative proposals for profiling the recovery by NIE of these revenue shortfalls after 2014.[2] Nominal prices are calculated using OBR forecasts for future RPI inflation.

TABLE 18.4 **NIE's allowed revenues under our provisional determination and adjustment for revenue shortfalls prior to October 2014**

	Prices	*Apr 12 Sep 12*	*Oct 12 Dec 12*	*Jan 13 Sep 13*	*Oct 13 Sep 14*	*Oct 14 Sep 15*	*Oct 15 Sep 16*	*Oct 16 Sep 17*	*Apr 12 Sep 17*
CC allowed revenues	Constant 2009/10	99	51	140	186	174	180	180	1,009
NIE's billed revenues	Nominal	100	53	158	211				
CC allowed revenues	Nominal	110	58	161	220	212	227	235	
Shortfall in NIE's allowed revenues in each period up to 30/09/14	Nominal	–10	–6	–3	–9				
Recovery of expected cumulative shortfall at 30/09/14 in each period	Nominal					13	8	8	
CC's PD of NIE's maximum revenues in each period between Oct 14 and Sep 17	Nominal					225	234	243	

Source: CC analysis.

18.59 We now set out in Table 18.5 the expected effect on customer tariffs. We do this in both real and nominal terms, expressed relative to RPI increases to 2013 and forecast RPI increases thereafter (actual allowed revenues will be adjusted for out-turn inflation).[3] In interpreting these year by year results, it is important to recall that the figures from 2014 include adjustments for NIE's under-recovery of revenues over the period from 1 April 2012 through to 30 September 2014. Therefore, in Table 18.6, we show the cumulative effect on NIE charges of actual and forecast changes, so as to

[2] As an approximation for the purpose of our provisional determination we have assumed that there was no revenue over-recovery at 1 April 2012, and that revenue in the period from October 2013 to September 2014 will be the same as NIE's forecast for October 2012 to September 2013 (since distribution use of system charges did not change on 1 October 2013). NIE reported a £6.8 million under-recovery (the K correction) as at 31 March 2012 across its use of system (UoS) and PSO charges combined in its 2011/12 regulatory accounts. In the absence of a breakdown of this balance between UoS and PSO charges, we have assumed for the provisional determination that this balance arises solely from PSO charges. Timing differences on PSO charges have been historically more significant than UoS charges. Our determination relates to UoS charges only.
[3] Following the approach adopted in the UR's model, all RPI increases are calculated with respect to the changes in the RPI between the mid-point of the year in question and the mid-point of the previous year. For example, for the year beginning 1 October 2012, the RPI increase is calculated using the values of the index at March 2012 and March 2013.

give a better indication of the overall effect of our provisional determination on customer charges.

TABLE 18.5 **Percentage annual increase in NIE's charges over period October 2012 to September 2017**

per cent

Price increase at 1 October each year	*Price changes already announced* 2012	2013	*RPI forecast and implied price changes to be announced* 2014	2015	2016
Real price change	1.7	–2.8	3.7	0.7	0.0
RPI increase (actual/latest OBR forecasts)	3.3	2.8	3.0	3.4	3.8
Nominal price increase	5.0	0	6.7	4.1	3.8

Source: CC analysis.

TABLE 18.6 **Cumulative percentage increase in NIE's real and nominal actual and forecast charges over period October 2012 to September 2017**

Cumulative percentage

	Actual 1 October 2012	2013	*Forecast 1 October* 2014	2015	2016
Real price change	1.7	–1.1	2.6	3.3	3.3
RPI increase	3.3	6.2	9.4	13.1	17.4
Nominal price increase	5.0	5.0	12.1	16.7	21.1

Source: CC analysis.

18.60 As can be seen from Table 18.3, relative to RPI, network charges are lower in the year commencing 1 October 2013 than in the previous year. Our provisional determination will see an increase in charges from October 2014 onwards, with the size of the increase relative to RPI declining in 2015 and unchanged in 2016. The nominal price increases will depend on actual changes in the RPI. In real terms, as shown in Table 18.4, our determination allows a small cumulative increase in charges of 3.3 per cent relative to RPI over the whole of the RP5 period (ie from April 2012). In nominal terms, forecast RPI growth over the period means that charges are expected to increase by 21 per cent, corresponding to an increase of around 5 per cent in a typical customer's total electricity bill.

18.61 For a representative domestic customer consuming 4,000 kWh a year, the electricity charges include approximately £130 a year for distribution charges payable by the supplier to NIE.[4] An additional cost of the order of £22 might be attributable to NIE's element of the transmission charges payable by the supplier and by generators to SONI.[5] The total contribution of an average domestic customer to transmission and distribution charges considered in this inquiry is therefore about £152 a year. Applying the cumulative price impacts, and assuming that SONI, generators and retailers pass through the changes in NIE's distribution and transmission charges in proportion to their current charges, in real terms this indicates an increase in these representative customer charges (comparing the forecast 2017 charges with those that applied in 2012) of around £5 a year in real terms, and £32 a year in nominal terms (using forecasts of RPI inflation).

18.62 The total allowed revenues in our determination may vary depending on whether NIE seeks, and the UR approves, allowances for additional investment projects for distribution network-load-related expenditure.[6] Actual nominal customer charges will also vary depending on out-turn RPI figures.

18.63 A direct comparison of the tariff effects of our redetermination with the UR's determination, and with NIE's proposals, is complex. The proposals span different periods from different start dates, and our redetermination also has to make an adjustment for NIE's underrecoveries in the period since April 2012. NIE might also choose to implement tariff increases differently for the different determinations. We consider that the most appropriate basis for comparison is the total allowed revenue (in real terms) standardized on the period 1 April 2012 to 30 September 2017. This is because we assume that tariffs will vary directly in line with allowed revenues.

[4] Based on 4,000 kWh and a distribution tariff of £10.39 a quarter plus 2.070p/kWh plus 5 per cent VAT.
[5] Based on an average transmission cost of 0.525p/kWh, from a transmission service charge of £42 million and total consumption of 8 billion kWh, applied to 4,000 kWh, plus 5 per cent VAT.
[6] Allowed revenues will also vary slightly with some other elements under our price control design, eg for pass-through costs.

18.64 We estimate that our determination's aggregate allowed revenues over 5.5 years are £1,009 million, whereas the UR determination's aggregate allowed revenues over 5.5 years were £1,078 million. Therefore NIE's charges for distribution and transmission use of system are expected to be about 6.4 per cent lower under our redetermination than they might have been under the UR's RP5 determination.

The overall public interest

18.65 As outlined above, we have reviewed aspects of the RP4 price control conditions and found them to operate against the public interest. We have found that substantial changes to the current price control design are required to address the adverse effects we have identified. The approach we have adopted is to consider for each aspect of the price control conditions what design will best serve the public interest and what level of cost allowance is appropriate. Our approach in applying the public interest test is set out in paragraphs 1.13 to 1.15.

18.66 We now examine the overall effect of the modifications that we have proposed in order to remedy or prevent the effects adverse to the public interest. Our provisional view, as explained below, is that the determination we have proposed does operate in the public interest.

18.67 We note that transmission and distribution use of system charges account for around a quarter of customer bills. Distribution charges vary significantly across the UK; compared with other parts of the UK, Northern Ireland does not have particularly high or particularly low distribution charges. The implications of our determination for charges are an increase of about 3.7 per cent in 2014, 0.7 per cent in 2015 and 0.0 per cent in 2016 in real terms (corresponding to a forecast[7] 6.7, 4.1 and 3.8 per cent in nominal terms). The cumulative increase in bills is 3.3 per cent (real) over the

[7] ie using OBR forecasts of RPI.

RP5 period (21.1 per cent nominal). As network charges are only a quarter to a fifth of total customer bills, this will contribute around 0.8 per cent to the real increase in final consumer bills relative to RPI, or around 5 per cent to the nominal increase in final consumer bills.

18.68 The implications for consumers in absolute terms are set out in paragraph 18.60. In real terms the changes are small, although including forecasted inflation the increase in network tariffs might contribute an additional £32 between 2012 and 2017 to a representative domestic consumer bill. While we recognize that any increase in costs is unwelcome to consumers (particularly at a time when there is upwards pressure on electricity bills), we note that the increases each year are, on average, relatively low. Our redetermination implies a lower increase in customer bills than the UR's proposals, and very substantially less than NIE's submissions, based on allowed revenues.

18.69 The duties require us to have regard to the interests of specified groups. We have not identified special circumstances applicable to the disabled or chronically sick, those of pensionable age, or those on low incomes, which would lead us to a different view on the general price control. Increases will have a greater impact on any customers who purchase relatively large amounts of electricity, for example the small number of domestic customers who rely on electric heating. But we do not consider that driving charges to their lowest possible level would be in the overall interests of consumers for the reasons in paragraph [1.14]. Concerns relating to vulnerable, very low income groups (whose concerns range far wider than just electricity charges) are better addressed by Government.

18.70 A crucial aspect is ensuring that the transmission and distribution networks are capable of meeting all reasonable demands for electricity. We equate this with ensuring that NIE is able properly to maintain its network, with minimal interruptions to supply, and that all reasonable increases in demand for electricity are met (through ensuring adequate transmission and distribution networks). Our provisional determination of capex allowances is intended to facilitate all investment projects necessary to maintain services to customers, projects which comply with applicable network design and meet other obligations, and also projects complying with applicable network design and planning standards, and/or which meet any other obligation, and have been sufficiently justified. In addition, we have allowed within our capex and opex allowances provision for repairs, maintenance, tree cutting and other items necessary to maintain supplies and to meet new demands for electricity, on the basis that such work is done efficiently. However, we have not included in our capex allowance funding for some projects where we were not convinced of the need for them.

18.71 It is likely that individuals residing in rural areas may be more likely than urban dwellers to suffer disruption of supply due to network faults, storm damage and so on. We have not included in our capex allowance funding for some projects proposed by NIE, for example to tackle risks of ice accretion and to install remote control facilities to improve 11 kV network performance. While these projects may have contributed to a reduction in supply disruption risks, we have evaluated them as providing poor cost effectiveness.

18.72 The development of renewable energy sources is facilitated by some network reinforcement projects and a provision for NIE to apply to the UR for approval to reinforce transmission networks as and when necessary in response to developments in renewable energy generation.

18.73 We have considered other aspects of the provisional determination and found no aspects which could be expected adversely to affect other listed objectives, for example development of the all-Ireland electricity market, or prevent the efficient use of electricity.

18.74 Our proposals are also intended to provide NIE with a determination which allows it to recover relevant costs and earn an appropriate return. We consider that it provides incentives to invest appropriately and operate efficiently, and that it is able to finance the activities required by its obligations, but does not impose unnecessary costs on consumers.

18.75 Ultimately it is a matter of judgement to balance the various aspects of the public interest in light of the relevant evidence. As we consider that our provisional determination strikes an appropriate balance, we conclude that it will, overall, operate in the public interest.

Other remarks

18.76 We have not in our provisional determination made any decision on the level of costs in relation to this redetermination that NIE will be awarded and so will be able to recover from customers. We will decide this matter in our final determination, taking account of whether we consider that the costs NIE has incurred have been relevant and necessary in assisting the redetermination and the extent to which we have accepted its views.

18.77 The UR raised concerns over NIE's asset management strategy, and other parties, particularly CCNI, raised concerns over a lack of transparency in NIE's investment policies and how these are assessed. We welcome the progress NIE has made in recent months, particularly in gaining PAS55 accreditation, and we do not propose to make any formal determination in this area. But we do believe that further publication by NIE of more detailed information on its asset management policies and practices would greatly improve transparency and contribute to informed debate, with consumer groups and others, about future effective regulation. This could include, for example, the approach that NIE takes to the evaluation of investment decisions affecting different parts of its transmission and distribution systems and how NIE interprets and complies with different aspects of its statutory duties, network planning standards and other obligations.