BEFORE THE COMPETITION AND MARKETS AUTHORITY

22 APRIL 2015

IN THE MATTER OF AN APPEAL UNDER SECTION 11C OF THE ELECTRICITY ACT 1989

NORTHERN POWERGRID (NORTHEAST) LIMITED

NORTHERN POWERGRID (YORKSHIRE) PLC

Appellants

-v-

THE GAS AND ELECTRICITY MARKETS AUTHORITY

Respondent

RESPONSE TO NOTICE OF APPEAL

ENERGY LICENCE MODIFICATION

CONTENTS

INTRODUCTION

1. This is the Response of the Gas and Electricity Markets Authority ("the **Authority**") to the Notice of Appeal submitted to the Competition and Markets Authority (the "**CMA**") on 27 February 2015 by Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) Plc (together the "**Appellants**" or "**NPg**").

2. NPg appeals under section 11C of the Electricity Act 1989 ("**EA89**") the Authority's decision of 3 February 2015 under section 11A EA89 ("the **Decision**") to modify the electricity distribution licences of the Appellants. The Decision gave effect to the electricity distribution sector price control, RIIO-ED1. By a decision dated 30 March 2015, the CMA granted NPg permission to appeal on the terms set out in its permission decision.

3. In this Response:

   (a) Where the Authority does not expressly respond to a paragraph of the Notice of Appeal, it does not admit the same;

   (b) Bare paragraph references are references to paragraphs of the Notice of Appeal unless otherwise indicated; and

   (c) The Authority adopts the abbreviations used in the Notice of Appeal for convenience only without any admission to the contents thereof.

4. Section 2 of NPg's Notice of Appeal summarises the arguments raised in the later substantive sections of NPg's appeal. In order to avoid duplication, and in the interests of the clarity of cross-references, the Authority's defence principally refers to paragraphs of the later substantive sections of the Notice of Appeal, rather than to paragraphs of the summary at section 2. For the avoidance of doubt, this should not be taken to indicate that the Authority accepts their contents.

5. The remainder of this Response is structured as follows:

(a) Part I contains a general introduction to the role of Ofgem and the Authority;

(b) Part II contains the Authority's submissions as to the statutory framework and appropriate standard of review.

(c) Part III contains an overview of the regulatory context; and

(d) Parts IV-VI contain the Authority's detailed submissions in relation to each of the three grounds of appeal raised by NPg.

For the CMA's convenience, Parts I to III of this Response are materially the same as Parts I to III of the Authority's response to the appeals by British Gas Trading Limited ("**BGT**").

6. Also for convenience, a glossary of terminology relating to RIIO-ED1 is attached as Annex 1.

7. In this Response, a number of documents are referred to that are included in a Response Document Bundle. Those documents are referred to in the form [RDB/x], where x is the tab number. In addition, a number of documents in the NPg bundle are referred to with the reference in the form [NPg/a/b/c/page (or para.) d/ para. e], where a is the volume number, b is the tab number, and c is the secondary tab number.

PART I - THE ROLE OF THE AUTHORITY AND OFGEM

8. The Authority is an independent regulator funded largely by the network companies which are licensed by the Authority to participate in the gas and electricity markets. The Authority consists of non-executive and executive members and a non-executive chair who oversee the work of, and provide strategic and policy direction for, Ofgem.

9. The Authority members are appointed by the Secretary of State at the Department of Energy and Climate Change ("**DECC**"). Non-executive members bring experience and expertise from a range of areas including industry, social policy, environmental work, finance and Europe. The Executive members of the Authority are Ofgem's Chief Executive, one Senior Partner and the Group Finance Director.

10. The Authority makes decisions on a wide range of regulatory matters. These decisions are based on work, for example gathering and analysing evidence, which is carried out on a day-to-day basis by Ofgem.

11. Ofgem is divided into five policy Divisions, namely Electricity Transmission, Smarter Grids & Governance, Markets, Sustainable Development and Ofgem E-serve. Each Division is headed by a Senior Partner. Below the Senior Partner in each Division are Partners and Associate Partners with particular areas of responsibility.

PART II: THE STATUTORY FRAMEWORK AND STANDARD OF REVIEW

The statutory framework

12. The appealed decisions were made by the Authority pursuant to s. 11A EA89 and subject to the statutory duties applying thereto, as set out below. By virtue of s. 11E(2) EA89, the CMA is in these appeals required to:

> *have regard, to the same extent as is required of the Authority, to the matters to which the Authority must have regard—*
>
> *(a) in the carrying out of its principal objective under section 3A;*
>
> *(b) in the performance of its duties under that section; and*
>
> *(c) in the performance of its duties under sections 3B and 3C.*[1]

13. By s. 3A(1B) EA89 the Authority is required to perform its functions under s. 11A EA89:

> *… in the manner which … the Authority … considers is best calculated to further the principal objective, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.* (emphasis added)

14. The principal objective is (s. 3A(1)):

> *… to protect the interests of existing and future consumers in relation to electricity conveyed by distribution systems or transmission systems*.[2] (emphasis added)

15. Section 3A(1A) provides further as follows.[3]

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[1] This provision defines matters to which the CMA must have regard. It does not serve to put the CMA in the shoes of the Authority. It does not follow that it is the CMA's function to substitute for the Authority's own judgment as to, for example, what is best calculated to further the principal objective.

[2] For the purposes of s. 3A the term "consumers" includes both existing and future consumers: s. 3A(6). The Authority agrees with NPg (at 3.20 of its Notice of Appeal), that consumers here includes end consumers of electricity.

(1A) Those interests of existing and future consumers are their interests taken as a whole, including—

(a) their interests in the reduction of electricity-supply emissions of targeted greenhouse gases;

(b) their interests in the security of the supply of electricity to them; and

(c) their interests in the fulfilment by the Authority, when carrying out its functions as designated regulatory authority for Great Britain, of the objectives set out in Article 36(a) to (h) of the Electricity Directive. (emphasis added)

16. Article 36 of the Electricity Directive[4] provides as follows.

In carrying out the regulatory tasks specified in this Directive, the regulatory authority shall take all reasonable measures in pursuit of the following objectives within the framework of their duties and powers as laid down in Article 37, in close consultation with other relevant national authorities including competition authorities, as appropriate, and without prejudice to their competencies:

(a) promoting, in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in electricity within the Community, and effective market opening for all customers and suppliers in the Community and ensuring appropriate conditions for the effective and reliable operation of electricity networks, taking into account long-term objectives;

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[3] Section 3A(5B) provides:
In subsection (1A)—
"emissions" has the same meaning as in the Climate Change Act 2008 (see section 97 of that Act);
"electricity-supply emissions" in relation to emissions of a targeted greenhouse gas, means any such emissions (wherever their source) that are wholly or partly attributable to, or to commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors;
"targeted greenhouse gases" has the same meaning as in Part 1 of the Climate Change Act 2008 (see section 24 of that Act).

[4] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

(b) developing competitive and properly functioning regional markets within the Community in view of the achievement of the objectives referred to in point (a);

(c) eliminating restrictions on trade in electricity between Member States, including developing appropriate cross-border transmission capacities to meet demand and enhancing the integration of national markets which may facilitate electricity flows across the Community;

(d) helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented, and promoting system adequacy and, in line with general energy policy objectives, 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;

(e) 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;

(f) ensuring that system operators and system users are granted appropriate incentives, in both the short and the long term, to increase efficiencies in system performance and foster market integration;

(g) ensuring that customers benefit through the efficient functioning of their national market, promoting effective competition and helping to ensure consumer protection;

(h) helping to achieve high standards of universal and public service in electricity supply, contributing to the protection of vulnerable customers and contributing to the compatibility of necessary data exchange processes for customer switching.

17. By s. 3A(1C) EA89 (together with the duty under s. 3A(1B) EA89, the "**principal objective duty**"):

before deciding to carry out functions … in a particular manner with a view to promoting competition as mentioned in subsection (1B), … the Authority shall consider—

(a) to what extent the interests referred to in subsection (1) of consumers would be protected by that manner of carrying out those functions; and

(b) whether there is any other manner (whether or not it would promote competition as mentioned in subsection (1B)) in which … the Authority … could carry out those functions which would better protect those interests. (emphasis added)

18. In performing the principal objective duty, the Authority is required by s. 3A(2) EA89 to:

… have regard to

(a) the need to secure that all reasonable demands 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 1 of EA89], the Utilities Act 2000, Part 2 or 3 of the Energy Act 2004, Part 2 or 5 of the Energy Act 2008 or section 4, Part 2, sections 26 to 29 of the Energy Act 2010 or Part 2 of the Energy Act 2013; and

(c) the need to contribute to the achievement of sustainable development.

(emphasis added)

19. In performing the above statutory duties, the Authority is further required to have regard (not exclusively) to the interests of four "*descriptions of consumers*", namely those who are disabled or chronically sick, of pensionable age, with low incomes, and those residing in rural areas: s. 3A(3).

20. By s. 132(2) of the Energy Act 2013 ("**EA13**"), the Authority must also:

(a) "*have regard to*" the strategic priorities set out in a strategy and policy statement published by the Secretary of State pursuant to s. 131 of EA13[5]; and

(b) "*carry out [its] regulatory functions in the manner which … the Authority … considers is best calculated to further the delivery of the policy outcomes [set out in the strategy and policy statement].*"

However, these duties (the "**EA13 duties**" and, together with the principal objective duty, the "**core statutory duties**") are subject to the application of the principal objective duty: s. 132(3) EA13.

21. Subject to the core statutory duties, the Authority is further required by s. 3A(5) to carry out its functions:

> *in the manner which … it considers is best calculated—*
>
> *(a) to promote efficiency and economy on the part of persons authorised by licences or exemptions to distribute, supply or participate in the transmission of electricity, to participate in the operation of electricity interconnectors or to provide a smart meter communication service and the efficient use of electricity conveyed by distribution systems or transmission systems;*
>
> *(b) to protect the public from dangers arising from the generation, transmission, distribution or supply of electricity or the provision of a smart meter communication service;*
>
> *(c) to secure a diverse and viable long-term energy supply,*
>
> *and shall, in carrying out those functions, have regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity or the provision of a smart meter communication service.*

[5] The strategy and policy statement has yet to be published. The consultation on the draft strategy and policy statement closed on 17 October 2014.

(emphasis added)

22. Section 3A(4) EA89 provides further that the Authority "may" (but is not required to) have regard to:

(a) the interests of consumers in relation to gas conveyed through pipes (within the meaning of the Gas Act 1986); and

(b) any interests of consumers in relation to–

(i) communications services and electronic communications apparatus, or

(ii) water services or sewerage services (within the meaning of the Water Industry Act 1991),

which are affected by the carrying out of [the Authority's] function.

23. In carrying out its functions in accordance with the above, the Authority must (s. 3A(5A) EA89) have regard to:

(a) the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed; and

(b) any other principles appearing to him or, as the case may be, it to represent the best regulatory practice.

24. Thus, the Authority is required to perform its functions under s. 11A EA89 within a complex, multi-layered legal framework that imposes upon the Authority a range of mandatory and discretionary duties, objectives and considerations. To the extent set out above, the hierarchy of those duties, objective and considerations is provided for by statute. Beyond that, it is incumbent for the Authority, acting within the statutory framework, to determine for itself the hierarchy of and weight to be attributed to various statutory considerations (*R v Director General of Telecommunications Ex parte Cellcom Ltd* [1999] E.C.C. 314, at [32]).

25. The interests of consumers are multiple and interrelated. When approached singly, they may be in tension with each other. The Authority is required to take them "as a whole", balancing and reconciling individual interests, including those of existing and future consumers.

26. NPg purports (at paragraph 3.21 of its Notice of Appeal) to identify what is required to protect the "interests of consumers as end users of electricity". Setting aside the fact that that is not the totality of the Authority's statutory obligations (see above), the interests asserted are overly simplistic and incomplete. The Authority does not dispute that consumers interests include those asserted there by NPg, but does not accept that the interests of existing and future consumers are limited to those asserted.

27. NPg (unsurprisingly) emphasises (at paragraphs 3.28 to 3.30) the adequacy of the remuneration that it receives and the financeability of its licensed functions. It is correct that the Authority is required to have regard to — among other things — the need to secure that licence holders are able to finance their licensed activities. Neither this nor any other relevant consideration of the adequacy of regulated remuneration is antithetical to the interests of consumers. It is not a case of consumers set against licence holders in diametric opposition. It is self-evident that consumers – both existing and future – have an interest in licence holders being adequately remunerated to be able efficiently to act in accordance with their interests, including in the adequacy and security of supply both now and in the future. It does not follow that the principal objective is synonymous with securing the financeability of NPg's licensed activities, nor that the Authority's task is merely to ensure the adequacy of the regulated remuneration. It is, however, also not the case, as BGT asserts (at paragraph 2.22(a) of its Notice of Appeal dated 2 March 2015) that "*the DNOs' need to ensure finance … is a subsidiary consideration, which arises only insofar as it is shown to be of relevance to the consumer interest*." It is a matter that the legislature has determined to be relevant and to which the Authority must accordingly have proper regard in performing the principal objective duty. The (in some cases, competing) interests of consumers must be taken as a whole and the

Authority must judge for itself what is best calculated in accordance with the entire statutory framework to protect those interests.

28. Any suggestion on the part of NPg (see paragraphs 3.27 and 3.30) that the Authority's obligation to have regard to the "need to secure" various matters amounts to a direct obligation on the part of the Authority to act so as to guarantee those matters is misconceived.[6]

    (a) In *R (Law Society of England and Wales v Lord Chancellor* [2012] EWHC 794 (Admin)), the court considered a similar obligation on the Lord Chancellor "*to have regard to the need to secure*" a provision of services under the Access to Justice Act 1999. The court held[7] that, if the Legislature had intended to secure the provision of services, "*one would expect it to have imposed a duty on the Lord Chancellor to secure that this need was satisfied. It did not do so, instead imposing the lesser duty to take that need into account*".

    (b) In *R (on the application of Baker) v Secretary of State* [2008] EWCA Civ 141, the Court of Appeal held that an obligation contained in the Race Relations Act 1976 to "*have due regard to the need to promote equality of opportunity and race relations*" was not "*a duty to achieve a result… it was a duty to have due regard to the need to achieve [the result]*". Due regard in this context was held to mean "*regard that is appropriate in all the circumstances*".[8]

29. In particular, if NPg is seeking to assert (at paragraph 3.30) that the Authority's obligation to "have regard to" the need to secure that licence holders are able to finance their regulated activities amounts to an obligation on the part of the Authority to ensure "*that DNOs are able to cover the reasonable costs of meeting the required Outputs and make reasonable returns on capital*", then that assertion is wrong. It is a matter to which the Authority must have regard. It has properly done so. Further, the matter to which the Authority must have regard in this respect is a licensee's ability to

[6] As BGT states at paragraph 2.22(a)
[7] at paragraph 52.
[8] at paragraph 31.

finance their regulated activities, not necessarily to make reasonable returns on capital in all circumstances.

30. NPg goes on to suggest at paragraph 3.32 that the Authority's duty (under s. 3A(5) EA89) to carry out its functions "*in the manner which … it considers is best calculated … to promote efficiency and economy*" is "less onerous" than its duty to have regard to the need to secure the matters referred to above. It is unclear what NPg means by this, but it should be noted that s. 3A(5) EA89 imposes a direct obligation[9] on the Authority, whereas s. 3A(2) EA89 imposes a number of mandatory relevant considerations to which the Authority must have regard.

31. The Authority's obligation under s. 3A(5) — and under the principal objective duty — is to act in the manner which "it considers" is best calculated to further or promote the specified objective. Contrary to both BGT's and NPg's apparent positions, this formulation makes clear that it is for the Authority to determine for itself what it "considers" to be "best calculated". That reflects the reality that such a determination necessarily involves a judgment based on the evidence. NPg implicitly — and correctly — accepts at paragraph 3.32 that the Authority has a margin of appreciation in making that judgment. The assertion that that margin of appreciation does not extend to choosing an approach that is "clearly inferior" is uncontentious: such a choice would not meet the threshold test in the *Wednesbury* case.[10]

The CMA's jurisdiction under s. 11E EA89

32. These Appeals are brought under section 11C(1) EA89, which provides that an appeal lies to the CMA against a decision by the Authority to modify licences under s. 11A EA89.

33. The CMA's jurisdiction to determine such appeals is wholly statutory. Section 11E EA89 creates and defines the jurisdiction of the CMA under s. 11C EA89,

[9] Albeit subject to ss. 3A(1B) and 3A(2) EA89, and s. 132(2) EA13

[10] *Associated Provincial Picture Houses Ltd v Wednesbury Corporation* [1948] 1 KB 223, [230]: a decision may be challenged as unreasonable if it "*is so unreasonable that no reasonable authority could ever have come to it*".

including defining exhaustively the basis and grounds on which the CMA may allow an appeal.[11] Section 11E EA89 provides as follows.

"(1) This section applies to every appeal brought under section 11C.

(2) In determining an appeal the CMA must have regard, to the same extent as is required of [the Authority], to the matters to which [the Authority] must have regard—

(a) in the carrying out of its principal objective under section 3A;

(b) in the performance of its duties under that section; and

(c) in the performance of its duties under sections 3B and 3C.

(3) In determining the appeal the CMA—

(a) may have regard to any matter to which [the Authority] was not able to have regard in relation to the decision which is the subject of the appeal; but

(b) must not, in the exercise of that power, have regard to any matter to which [the Authority] would not have been entitled to have regard in reaching its decision had it had the opportunity of doing so.

(4) The CMA may allow the appeal only to the extent that it is satisfied that the decision appealed against was wrong on one or more of the following grounds—

(a) that [the Authority] failed properly to have regard to any matter mentioned in subsection (2);

(b) that [the Authority] failed to give the appropriate weight to any matter mentioned in subsection (2);

(c) that the decision was based, wholly or partly, on an error of fact;

[11] See *Anisminic Ltd v Foreign Compensation Commission* [1969] 2 AC 147.

(d) that the modifications fail to achieve, in whole or in part, the effect stated by [the Authority] by virtue of section 11A(7)(b);

(e) that the decision was wrong in law.

(5) To the extent that the CMA does not allow the appeal, it must confirm the decision appealed against.…" (emphasis added)

34. The present appeals are the first under s. 11C EA89 (such appeals hereafter referred to as "**energy licence modification appeals**"). Neither the CMA nor its predecessor, the Competition Commission ("**CC**"), has considered its jurisdiction under s. 11E EA89. It is a matter for the CMA in the first instance to determine its jurisdiction.[12]

35. It is common ground that:

(a) the CMA's jurisdiction is a question of law that the CMA must determine in order to conduct the appeal;[13]

(b) the grounds of appeal are not co-extensive with judicial review grounds of illegality, irrationality and procedural impropriety[14] (see BGT Notice of Appeal, at paragraph 2.18; NPg Notice of Appeal, at paragraph 3.8); and

(c) the statutory grounds of appeal in energy licence modification appeals are substantively identical to the statutory grounds in appeals under s. 173 and 175(4) of the Energy Act 2004[15] ("**Energy Act appeals**").[16]

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[12] *Anisminic*, at pages 206-215, per Lord Wilberforce.

[13] *ibid*, per Lord Wilberforce.

[14] Although these grounds and those contained in s. 11E EA89 are not the same, it should be noted that judicial review, at least in the High Court, is a flexible mechanism arising from the Court's original jurisdiction and not merely statute. See, for example, *IBA Healthcare v OFT* [2004] EWCA Civ 142, at paragraph 100. This may include a consideration of the merits of a decision, where the circumstances of the case require. For example, see *Wilkinson v Broadmoor Special Authority* [2001] EWCA Civ 1545 and *T-Mobile (UK) Ltd and Telefonica 02 UK Ltd v Ofcom* [2008] EWCA Civ 1373 ("***T-Mobile***").

[15] Section 175(4) of the Energy Act 2004 provides:

The CMA may allow the appeal only if it is satisfied that the decision appealed against was wrong on one or more of the following grounds—

(a) that [the Authority] failed properly to have regard to the matters mentioned in subsection (2);

Accordingly, the CC's consideration of its jurisdiction in Energy Act appeals in *E.ON UK Plc and GEMA and British Gas Trading Limited: Decision and Order of the Competition Commission* ("***E.ON***") is highly relevant: see paragraphs 49 *et seq* below.

Telecoms appeals

36. Both Appellants seek to rely[17] on comparisons with the appellate jurisdiction of the Competition Appeal Tribunal ("**CAT**") under ss. 192 and 193 of the Communications Act 2003 ("**CA 2003**") ("**Telecoms appeals**"), and the CMA's role on reference in appeals thereunder relating to price control decisions. Although there are some similarities (as there are with judicial review[18]), the comparisons drawn are misconceived and disregard the fundamental differences between Telecoms appeals and the CMA's statutory jurisdiction in these Appeals. BGT's assertion at paragraph 2.17 that ss. 11C and 11E EA89 provide for a "*full appeal on the merits*" is unfounded and unsustainable.

37. If the legislature had intended to provide a form of statutory judicial review, the statute would have said so;[19] it did not. If the legislature had intended to provide for an appeal on the merits, it would have said so; it did not. It is a fundamental principle of statutory construction that the words of the legislation should be given their natural meaning unless to do so leads to absurdity.[20] Where the legislature has chosen different words, it is to be presumed that a

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(b) that [the Authority] failed properly to have regard to… the purposes for which the relevant condition has effect… [this ground is analogous to s. 11E(4)(d) EA89 ("the modifications fail to achieve… the effect stated")]

(c) that [the Authority] failed to give the appropriate weight to one or more of those matters or purposes;

(d) that the decision was based, wholly or partly, on an error of fact;

(e) that the decision was wrong in law.

[16] See BGT Notice of Appeal, at paragraph 2.18-2.19; NPg Notice of Appeal, at paragraph 3.5).

[17] BGT, at paragraph 2.20 of its Notice of Appeal, states that the CC's approach in Telecoms appeals "accords with" the approach taken in E.ON, without further explanation. NPg, at paragraph 3.11 of its Notice of Appeal, states that the CC's approach in Telecoms appeals is "also relevant", without providing further explanation as to why this is the case.

[18] For example, both Appellants argue, and the Authority agrees, that the relevant statutory ground that the decision is wrong in law (s. 11E(4)(e) EA89) includes the public law concept of procedural unfairness/natural justice.

[19] See, for example, the CAT's jurisdiction under Schedule 8 to the Competition Act 1998 and s. 317 CA 2003.

[20] Known as the "Golden Rule" of statutory interpretation; see, for example, *Grey v. Pearson* (1857) 10 E.R. 1216.

different meaning and effect was intended. There is no basis on which to assert that s. 11E EA89 was intended to create a right of appeal of a similar nature to one provided for in wholly different terms. To the contrary, the two statutory jurisdictions are fundamentally different.

The CAT's jurisdiction

38. A right of appeal against certain decisions of the Office of Communications ("**Ofcom**") lies to the CAT under s. 192 of the CA 2003.[21]

39. Section 192 of the CA 2003 provides as follows.

> *"[…]*
>
> *(3) The means of making an appeal is by sending the Tribunal a notice of appeal in accordance with Tribunal rules.*
>
> *[…]*
>
> *(5) The notice of appeal must set out—*
>
> > *(a) the provision under which the decision appealed against was taken; and*
> >
> > *(b) the grounds of appeal.*
>
> *(6) The grounds of appeal must be set out in sufficient detail to indicate—*
>
> > *(a) to what extent (if any) the appellant contends that the decision appealed against was based on an error of fact or was wrong in law or both; and*
> >
> > *(b) to what extent (if any) the appellant is appealing against the exercise of a discretion by OFCOM, by the Secretary of State, by the CMA or by another person.*

[21] Sections 192 to 196 CA 2003 implement Article 4 of Directive 2002/21/EC on the common regulatory framework for electronic communications networks and services (the "**Framework Directive**").

[…]"

(emphasis added)

40. Section 195 CA 2003 sets out how the CAT must dispose of an appeal under s. 192 CA 2003.

"(1) The Tribunal shall dispose of an appeal under section 192(2) in accordance with this section.

(2) The Tribunal shall decide the appeal on the merits and by reference to the grounds of appeal set out in the notice of appeal.

(3) The Tribunal's decision must include a decision as to what (if any) is the appropriate action for the decision-maker to take in relation to the subject-matter of the decision under appeal.

(4) The Tribunal shall then remit the decision under appeal to the decision-maker with such directions (if any) as the Tribunal considers appropriate for giving effect to its decision.

[…]"

(emphasis added)

41. It is notable that, by contrast to the CMA in these Appeals:

(a) the CAT is required to decide the appeal on the merits;[22]

(b) the CAT's jurisdiction is not limited to finding the decision wrong on one or more specified grounds; and

(c) the CAT is required to dispose of the appeal by reference to the grounds set out in the notice of appeal but the appellant is not

[22] Section 192(2) CA 2003; cf. s.11E EA89 which provides that the CMA "*may allow the appeal only to the extent that it is satisfied that the decision appealed against was wrong on one or more of the [statutory] grounds*". The CC in *E.ON* (at paragraph 5.12) held that s. 11E EA89 does not give the [CMA] jurisdiction to conduct a full rehearing of the reasons for the decision, but rather to provide a check on the process by which the Authority came to make its decision, including whether the Authority failed to properly have regard to its duties, erred in fact or erred in law.

constrained in its notice of appeal to specific grounds of the sort provided for in energy licence modification appeals.[23]

42. These provisions of the CA 2003 implement (in part) the UK's obligations under Directive 2002/21/EC[24] (the "**Framework Directive**"). Article 4(1) of the Framework Directive provides:

> *"Member States shall ensure that effective mechanisms exist at national level under which any user… who is affected by a decision of a national regulatory authority has the right of appeal against the decision to an appeal body that is independent of the parties involved.… Member States shall ensure that the merits of the case are duly taken into account…".* (emphasis added)

43. By contrast, the provisions for energy licence modification appeals under EA89, as amended, implement the UK's obligations under Directive 2009/72/EC[25] (the "**Electricity Directive**"), which provides, at article 37(17) that:

> *"Member States shall ensure that suitable mechanisms exist at national level under which a party affected by a decision of a regulatory authority has a right of appeal to a body independent of the parties involved and of any government."* (emphasis added)

There is no requirement in the Electricity Directive that member states enact domestic legislation that establishes an appeal mechanism that "takes into account" the merits of the original decision, as in the Framework Directive.

44. It should be noted that even the Framework Directive requirement to provide for an appeal taking account of the merits does not require a full merits appeal before the CAT; it can be – and indeed in some instances is – met by judicial

[23] Sections 192(6) and 195(2) CA 2003.
[24] Directive 2002/21/EC of the European Parliament and of the Council of 7 March 2002 on a common regulatory framework for electronic communications networks and services.
[25] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

review.[26] Thus, the Telecoms appeals mechanism goes beyond that which is required by the Framework Directive, in respect of some – but not all – decisions by Ofcom that are subject to the Framework Directive's requirement for an appeal taking account of the merits.

45. BGT relies (at paragraph 2.19 of its Notice of Appeal) on the Government Response to the Department of Energy and Climate Change's consultation on the 'Implementation of the EU Third Internal Energy Package', January 2010 [BG2/1]:

> *"... in the case of E.ON UK Ltd v GEMA on Energy Code Modification UNC116 (CC 02/07), the Competition Commission took the view that the grounds for appeal enabled it to go beyond a narrower judicial review approach and to consider the merits of the case. It is the Government's intention that the proposed grounds for appeal for licence modification decisions also enable the appeal body to take account of the merits of the case in a similar manner. The Government considers the Competition Commission's approach in relation to code modifications to be helpful in this regard."*

That statement is not disputed. It lends no support to any false proposition that what was intended or implemented by s. 11E EA89 amounts to an appeal on the merits. It does not.

The CMA's role

46. Telecoms appeals are conducted in accordance with the Competition Appeal Tribunal Rules 2003 (the "**CAT Rules**"), the CAT's stand-alone rules on procedure.[27] Where the decision of Ofcom appealed against concerns the setting of price controls, the CMA is required by s. 193 CA 2003 and rule 3 of the Competition Appeal Tribunal (Amendment and Communications Act Appeals) Rules 2004 to refer any price control matter[28] raised by the appeal to

[26] *T-Mobile UK Limited v Ofcom* [2008] CAT 15, at paragraph 42, approved in the Court of Appeal in *T-Mobile* ([2008] EWCA Civ 1373), at paragraph 10.
[27] SI 2003/1372
[28] "Price control matter" is defined in s. 193(10) CA 2003 as an imposition of any form of price control authorised by ss. 87(9), 91 or 93(3) of the CA 2003.

the CMA (formerly the CC) for determination, and to apply the CMA's determination when deciding the appeal. Pursuant to s. 193(2) CA 2003, the CMA's determination must be made:

(a) in accordance with the CAT Rules;

(b) in accordance with any directions given by the CAT; and

(c) subject to the CAT Rules and any such directions, using such procedures as the CMA considers appropriate.

The CMA has no independent power to go beyond the legal framework within which the appeal is to be determined by the CAT.

47. Nevertheless, to the extent that the Appellants seek to rely on the CMA's role in Telecoms appeals, the Authority acknowledges that there are similarities in the subject matter before the CMA in such cases and in the present appeals, and fully acknowledges the choice of the legislature to give both tasks to the CMA, a specialist body with appropriate expertise in regulatory and price control matters.

48. It is, however, to be noted that the CMA's role in each is deliberately distinct. In energy licence modification appeals, the CMA is the appellate body, charged with finally disposing of the appeal before it in accordance with its statutory jurisdiction. In Telecoms appeals, the CAT is the appellate body performing that function. The CMA's role in Telecoms appeals is prescribed by the CAT pursuant to the statutory scheme and its conclusions are subject to the CAT's endorsement and implementation in its decision.

Energy Act appeals: the CC's observations in the E.ON case

49. It is not in dispute that the statutory grounds of appeal in Energy Act appeals are substantively identical to the statutory grounds of appeal in these Appeals and therefore the CC's comments on its jurisdiction in Energy Act appeals in *E.ON* is relevant to the CMA's determination of its jurisdiction in the present appeals. The Appellants have referred to the CC's decision in *E.ON* but have not fully reflected the CC's reasoning.

50. In particular, the CC, when considering its jurisdiction, found that, as an appellate body, its jurisdiction could usefully be compared to that of appellate courts when reviewing decisions of trial judges under CPR 52, where the threshold for allowing the appeal is also whether the decision was "wrong".[29]

51. CPR 52, to the extent that is relevant for present purposes, provides that "*[t]he appeal court will allow an appeal where the decision of the lower court was (a) wrong… [subsection (b) is not relevant]*". The White Book commentary on CPR 52[30] provides that "*'wrong' presumably means that the court below (i) erred in law or (ii) erred in fact or (iii) erred (to the appropriate extent) in the exercise of its discretion*". Accordingly, an appellate court may allow the appeal against an impugned decision under CPR 52 where the decision was wrong by virtue of one or more of these types of errors. The approach taken by the courts in relation to an impugned decision will depend on the nature of the purported error.

52. In *E.ON*, the CC also adopted this approach, first considering its jurisdiction in relation to the Authority's exercising of its discretion (paragraphs 5.5-5.14), then errors of fact (paragraphs 5.15-5.17), and, finally, errors of law (paragraphs 5.18-5.19), and applying the reasoning of relevant CPR 52 cases concerning the appropriate standard of review.

53. The CC's reasoning in E.ON is considered below. The Authority respectfully submits that the CMA should adopt the reasoning of the CC in *E.ON* in relation to the present appeals.

Errors in the exercise of discretion

54. In relation to errors in the exercise of discretion, the CC held in *E.ON* that the grounds of appeal set out in s. 175(4) of the Energy Act 2004, which are in materially identical terms to the grounds of appeal in the present appeals, clearly foresaw circumstances in which the CC might reach a different view from the Authority on the merits but in which it could not be said that the Authority's decision was "wrong" on one of the statutory grounds:

[29] *E.ON*, at paragraph 5.4.
[30] at CPR 54.11.4.

> *"… we consider that [the Authority's] decision will require the exercise of judgment or discretion in applying [the] statutory and regulatory framework to what will often be complex facts… leaving to one side errors of law, it is not our role to substitute our judgment for that of [the Authority] simply on the basis that we would have taken a different view of the matter were we the energy regulator*."[31]

55. NPg recognises, at paragraph 3.12 of its Notice of Appeal, that:

> *"… there is a line that must be drawn in deciding whether a particular decision of [the Authority] is wrong on one (or more) of the statutory grounds… or whether the decision is one that the CMA might not have taken itself were it regulator, but which is not wrong on one (or more) of the statutory grounds…"*

56. NPg asserts that it has limited its appeal to areas in which it considers that the Authority has exceeded any margin of regulatory discretion such that the Authority's decision was "wrong". Where the line is drawn in relation to the "wrongness" of the Authority's decision is a question of law for the CMA. The Authority disagrees that NPg has drawn the line in the right place: in truth, NPg disagrees with discretionary judgments made by the Authority but cannot show that the Decision itself was wrong on one or more of the statutory grounds.

Errors of fact

57. In relation to errors of fact, the CC held that it should be slow to impugn findings of fact made by the Authority in Energy Act appeals, but that it had a clear jurisdiction in respect of factual errors, and would exercise that jurisdiction where it concluded that the Authority had based its decision on a plain error of fact.[32]

58. In doing so, the CC relied on the guidance set out in *Assicurazioni Generali Spa v Arab Insurance Group* [2003] 1 WLR 577, in which Clarke LJ drew a distinction between (a) conclusions of primary fact based on, or inferred from,

[31] *E.ON*, at paragraph 5.10-5.11.
[32] *E.ON*, at paragraph 5.15-5.16.

oral and/or documentary evidence before the appellate body; and (b) "*evaluations of the facts*" which "*involve an assessment of a number of different factors which have to be weighed against each other".* As to the latter, Clarke LJ added, importantly: "*This is…often a matter of degree upon which different judges can legitimately differ. Such cases may be closely analogous to the exercise of a discretion and, in my opinion, appellate courts should approach them in a similar way*".[33] The appropriate approach to be taken in relation to different findings of fact will depend on:

> *"… the weight to be attached to the findings of the judge and that weight will depend upon the extent to which, as the trial judge, the judge has an advantage over the appellate court; the greater that advantage the more reluctant the appellate court should be to interfere…".*[34]

59. Clarke LJ referred in his judgment[35] to the Court of Appeal's judgment in *Tanfern Ltd v Cameron-MacDonald (Practice Note)* [2000] 1 WLR 1311, where Brooke LJ gave the judgment of the court and said this, at paragraphs 30 - 32:

> *"The appellate approach: the general rule*
>
> *As a general rule, every appeal will be limited to a review of the decision of the lower court. This general rule will be applied unless a practice direction makes different provision for a particular category of appeal, or the court considers that in the circumstance of an individual appeal it would be in the interests of justice to hold a rehearing: CPR r 52.11(1). The appeal court will only allow an appeal where the decision of the lower court was wrong, or where it was unjust because of a serious procedural or other irregularity in the proceedings in the lower court: CPR r 52.11(3).*
>
> *This marks a significant change in practice, in relation to what used to be called 'interlocutory appeals' from district judges or masters. Under*

[33] *Arab Insurance*, at paragraphs 14-16.
[34] Ibid, at paragraph 15.
[35] Ibid. at paragraphs 8 – 9.

the old practice, the appeal to a judge was a rehearing in the fullest sense of the word, and the judge exercised his/her discretion afresh, while giving appropriate weight to the way the lower court had exercised its discretion in the matter. Under the new practice, the decision of the lower court will attract much greater significance. The appeal court's duty is now limited to a review of that decision, and it may only interfere in the quite limited circumstances set out in CPR r 52.11(3).

The first ground for interference speaks for itself. The epithet 'wrong' is to be applied to the substance of the decision made by the lower court. If the appeal is against the exercise of a discretion by the lower court, the decision of the House of Lords in G v G (Minors: Custody Appeal) [1985] 1 WLR 647 warrants attention. In that case Lord Fraser of Tullybelton said, at p 652: 'Certainly it would not be useful to inquire whether different shades of meaning are intended to be conveyed by words such as "blatant error" used by the President in the present case, and words such as "clearly wrong", "plainly wrong", or simply "wrong" used by other judges in other cases. All these various expressions were used in order to emphasise the point that the appellate court should only interfere when they consider that the judge of first instance has not merely preferred an imperfect solution which is different from an alternative imperfect solution which the Court of Appeal might or would have adopted, but has exceeded the generous ambit within which a reasonable disagreement is possible'." (emphasis added)

60. Having referred to Clarke LJ's guidance, the CC held in *E.ON*:

"Applying these principles, our view is that [the Authority], as the specialist regulator may well have an advantage over the CC in finding the relevant primary facts. In some respects, the advantage may be less than that which the trial judge has over the Court of Appeal, because [the Authority's] decisions are not based on the evidence and cross examination of witnesses. [The Authority] nevertheless has an

advantage of experience, and will often have the benefit of having conducted a consultation with the industry…"[36]

61. The CC also considered that the words "*based… on an error of fact*" (emphasis added) in the relevant statutory ground should be interpreted as a materiality threshold, such that the appellant would need to demonstrate that the error was material to the outcome of the decision. Only if the error was material would the CC regard the decision as "*wrong*" under the relevant ground.[37]

62. The CC in *E.ON* applied the materiality threshold and afforded a degree of respect to the Authority in relation to its findings of fact, such that the threshold for establishing that the Authority's findings of fact were sufficient to render its decision "wrong" was a particularly high one.[38] The Authority respectfully submits that the CC was right to do so and the CMA would be right to do so in the Appeals, having particular regard to (a) the lengthy and resource-intensive process undertaken by the Authority and the expertise it has brought to bear in doing so and (b) the fact that the Authority's determination involved, in many material respects, "*evaluations of the facts*" which "*involve an assessment of a number of different factors which have to be weighed against each other"* such that the appropriate test on appeal is closely analogous to that which applies to an appeal against the exercise of a discretion.

Errors of law

63. The CC in *E.ON* held that the relevant ground that the decision was "wrong in law" incorporated the public law concept of procedural fairness/natural justice.[39] Both Appellants argue, and the Authority agrees, that this is also the case in relation to the equivalent ground of appeal in the present appeals (s. 11E(4)(e) EA89). The Authority submits that it has complied with its public

[36] *E.ON*, at paragraph 5.16
[37] *E.ON*, at paragraph 5.17.
[38] In particular, in relation to errors of fact, the CC held at paragraph 7.15 that none of the errors it had identified in the Authority's cost-benefit analysis amounted to errors of fact.
[39] *E.ON*, at paragraph 5.18.

law duties in relation to the procedure that it adopted in reaching the Decision, as outlined in more detail below.

64. NPg's assertion that "wrong in law" also "catches basic arithmetic errors" is unfounded and unsupported by the case authority cited in support of it. *Danae Air Transport v Air Canada* [2000] 1 WLR 395 concerned an order for costs made by arbitrators against the claimant in an arbitration on the basis that it had been awarded less than the defendant had previously offered as settlement. In fact, the claimant had been awarded more than had been offered by way of settlement; the arbitrators had made a simple mathematical error when calculating the amounts. The arbitrators refused to accept the error, despite lengthy argument, and justified their decision with written reasons. The claimant applied to the courts to have the award remitted to the arbitrators under s. 22 of the Arbitration Act 1950. The judge at first instance refused on the basis that the mathematical error was either an error of fact or of law and therefore the court had no jurisdiction to remit (under s. 1(1) of the Arbitration Act 1979 (the "**1979 Act**")). The Court of Appeal reversed the decision on the basis that the error was not an error of fact or of law; it amounted to a "procedural mishap", in respect of which the court had jurisdiction to remit despite s. 1(1) of the 1979 Act.[40]

65. In the entirely different context of the present appeals, basic arithmetic errors by the Authority in the process of making its decision could only properly be characterised as errors of fact.[41]

The relevant context in the Appeals

66. When determining whether the Authority's decision was "wrong" on one or more of the statutory grounds, the CMA should first determine whether the purported error is an: (a) error of law; (b) error of fact; or (c) error in the exercise of discretion. The CC's judgment in *E.ON* also makes clear that, when considering the appropriate degree of respect to be afforded to a specialist regulator, an appellate body should consider (a) the nature of the

[40] See, in particular, the case authorities cited at pages 402-403.
[41] As noted above in relation to errors of fact, whether such errors would be sufficient to render the decision "wrong" for the purposes of the relevant statutory ground is a separate question.

decision; and (b) the relative positions of the primary decision maker and the appellate body in assessing the evidence.[42] In particular, as set out above, in appeals brought in the context of a challenge to the Authority's "evaluation of facts" the approach of the CMA will be closely analogous to that applicable to an appeal from an exercise of discretion.

67. These three types of error can be aligned with the five statutory grounds in the present appeals as follows.

(a) It is clear that, where the Authority has made an error of fact or law, the relevant statutory grounds will be whether the decision challenged was "wrong" on the basis of that error of fact or error of law (s. 11E(4)(c) EA89 and s. 11E(4)(e) EA89, respectively).

(b) Where the Authority has made an error in the exercise of its discretion, the relevant grounds may be whether the decision challenged was "wrong" on the basis that the error in the exercise of discretion amounted to a failure to have proper regard or give appropriate weight to the Authority's statutory duties (s. 11E(4)(a) EA89 and s. 11E(4)(b) EA89, respectively).

(c) Both errors of fact and errors in the exercise of discretion may also be relevant when considering whether the decision challenged was "wrong" on the basis that the modifications fail to achieve, in whole or in part, the stated effect (s. 11E(4)(d) EA89).

68. In order for the CMA to be satisfied that the Authority's decision was wrong, the Appellants must show that the Authority erred sufficiently when making the decision so as to make the decision "wrong" on one of the statutory grounds. In making its decision, the Authority was required to weigh a number of competing factors and considerations in order to ensure that the decision complied with its statutory duties. The Authority was also required, by virtue of certain of its relevant statutory duties (such as promoting competition and

[42] See the citation from *Tanfern* above. Also see, in relation to the application of the standard of review in the context of CPR 52, *E I Dupont de Nemours & Co v S T Dupont* [2006] 1 WLR 2793, at paragraphs 82 – 98, where *Assicurazioni Generali Spa* and *Tanfern* were discussed and applied.

protecting the interests of consumers), to approach its task in a holistic manner, taking account of all of the relevant factors and to make the decision as a whole. Under s. 11E(2) EA89, the CMA is required to have regard to the Authority's statutory duties to the same extent as the Authority when reviewing the Authority's decision under s. 11C EA89.

The nature of the decision

69. The decision under challenge in the present appeals is technically complex and is made up of a number of discrete but inter-connected determinations that together give rise to the decision itself. The Appellants' complaints do not go to all aspects of the decision, instead focussing on particular determinations, but not others. The Appeals can only be allowed on these specific complaints. However, the CMA is required to determine whether they render the decision itself wrong. It must do so by reference to the decision as a whole and be mindful of the distortive effects that may arise from artificially cherry picking aspects of the decision for reconsideration.

The decision-making process

70. As is clear from these submissions and the supporting evidence, the Authority's decision was a complex regulatory judgment, involving the balancing of many considerations, made from scratch on the basis of third party responses to the Authority's consultation and its own internal assessment, based on substantial amounts of data and expert consideration. In this respect, the context is somewhat different from that in the *E.ON* appeal, which concerned the adoption by the Authority of one of a number of competing third party proposals on the basis of recommendations by another body, evidence of which was available for review by the CC in *E.ON* (albeit that this involved considerable economic and regulatory assessment and judgment).

71. As a result of the decision-making process that led to the decision that is the subject of the present appeals, the decision is necessarily only a summary of the Authority's full determinations based on the available evidence and the expert consideration.

PART III: REGULATORY CONTEXT

Introduction

72. This section sets out the context to the Appeal. In turn, it briefly sets out in the following three subsections:

    (a) first, how the regulation of DNOs has developed since the privatisation of the sector in 1990;

    (b) secondly, the principles that the Authority applied in adopting the RIIO framework of regulation, which was an updated form of regulation for gas and electricity network operators in Great Britain; and

    (c) thirdly, how the Authority applied the new regulatory model to the electricity distribution networks in the specific context of RIIO ED-1.

History and background to the development of regulation of DNOs

73. As part of the process to bring about the privatisation of the electricity sector in Great Britain in 1990, 14 Public Electricity Suppliers were created, responsible for the supply and distribution of electricity in the areas covered by the 12 Area Boards in England and Wales and the 2 vertically integrated Scottish companies. To allay concerns that these private businesses might abuse their monopoly position, they had the charges they levied restricted through a form of revenue regulation known as “RPI-X”, with separate controls for the distribution and supply parts of the businesses.

74. Subsequently, competition was introduced into the electricity supply market in phases up to 1999 and price controls were lifted for that part of the value chain. However, in recognition of the fact that the distribution networks were effectively natural monopolies, they continued to be subject to RPI-X regulation.

75. This section:

    (a) first, explains the RPI – X form of regulation and how it has evolved since privatisation; and

(b) secondly, briefly sets out the key finding of a major review of the RPI-X regime that coincided with 20 years of its operation (and was known as RPI – X @ 20).

RPI-X

76. The RPI-X framework was first applied in 1984 to British Telecom at the time of its privatisation. It followed a report by Stephen Littlechild, then an academic economist, for the UK Government in 1983 that proposed a new approach for regulating private sector monopoly businesses. It was subsequently applied by the Director General of Gas Supply to the gas sector associated with the privatisation of British Gas in 1986. The Director General of Electricity Supply then applied the same approach in the context of the privatisation of the electricity sector (which also involved the privatisation of the transmission networks).

77. One of the key issues that Stephen Littlechild sought to address in establishing the RPI-X approach to regulation was to provide incentives for the regulated company to become more efficient and, in so doing, break the asymmetry of information between regulated company and the regulator. His solution was for the regulator to set, ex ante, the amount of revenue that the regulated operator was allowed to recover from its customers for a fixed period of time – typically 5 years. Over this fixed time period, the regulated operator was allowed to keep any differences between the actual costs it incurred in providing the services and the revenue allowance set by the regulator. This was expected to create strong incentives for cost efficiency – the lower the regulated operator's costs, the more profits it would generate. However, in so doing, it would reveal to the regulator the true level of costs it could deliver the services for. Hence, at the end of the fixed time period, the regulator could use this lower level of observed costs as the basis for setting the allowed revenue for the following five year period.

78. This approach of information revelation through incentive-based regulation has been central to the evolution of price controls for DNOs, and for energy network operators in GB more widely. The Director General of Electricity Supply and subsequently the Authority applied this RPI-X approach to the

electricity DNOs in five price control reviews (labelled DPCR1 to DPCR5) following the initial RPI-X arrangements which were part of the privatisation package. Over this period, the form of the price controls developed in the light of experience and the changing context.

79. The timing of the preparation of the fifth price control review, DPCR5, coincided with the Authority starting a review of RPI-X regulation, called the RPI-X@20 review (discussed further below). As a result, DPCR5 was a significant step towards the RIIO framework. It had an increased focus on outputs in some areas, provided funding for innovation trials, and placed greater emphasis on the role networks would need to play to facilitate the transition to a low carbon economy.

RPI-X@20

80. The RPI-X regime was generally regarded to have been very successful. However, in 2008 the Authority considered that it was timely to commence a review of the regulatory framework to consider whether it:

(a) was still fit for purpose. The RPI-X framework was 20 years old, and there was a desire to analyse both the effectiveness and appropriateness of the model for future application.

(b) would meet new and emerging challenges. The energy networks were required to play a key role in moving to a low carbon economy, requiring significant changes and investment, and consideration needed to be given to whether the regulatory framework should change as a result.

81. Recognising these issues and the need to step back and consider holistically the appropriate regulatory framework, the Authority launched a comprehensive review of the way in which Britain's gas and electricity networks were regulated. This review was known as RPI-X@20 in recognition that it was taking place 20 years after the introduction of the RPI-X regime in energy.

82. The review concluded that RPI-X had delivered significant benefits for consumers, including reductions in network charges, improvements in operating efficiency, more efficient financing, improved quality of service and increased investment. However, several areas for development were also identified. These were:

(a) stakeholders suggested the RPI-X framework led network operators to focus on the short term, and on Ofgem, rather than customers. They felt there was limited consideration of innovation and how best to deliver it, potentially limited appetite for risk, and a bias for 'capex' solutions rather than non-network options.

(b) such factors made RPI-X unlikely to facilitate the transformation to a low carbon economy and ensure security of supply in an efficient manner.

(c) there were concerns the regime had become complex making it difficult for stakeholders to understand, respond to and engage with.

(d) the process of submitting cost forecasts which were reviewed by the Authority at the same time as developing the various incentives and financial components for the price control created uncertainty and disagreement. This made it more difficult to assess whether costs were efficient and it was not a transparent process for stakeholders; and

(e) the RPI-X framework led companies to focus on efficiency which could be at the expense of delivering on outputs (such as customer service) and the longer term health of the network.

83. The RPI-X@20 review also took into account the changes to the Authority's statutory duties that had been adopted at around the same time, including:

(a) The Energy Act 2008, which clarified that the principal objective of the Authority to protect the interests of "consumers" related to the interests of "existing and future consumers"; and

(b) The Energy Act 2010 which made two clarifications which were:

(i) first, when interpreting the Authority's principal objective of protecting the interests of existing and future consumers, there was a need to reduce greenhouse gas (GHG) emissions and ensure security of supply; and

(ii) second, to consider alternative types of solutions to protect consumers instead of, or alongside, measures to promote competition.

RIIO principles

84. In October 2010 the Authority published its RPI-X@20 decision document. It detailed a new regulatory framework, known as the RIIO model. RIIO involves setting Revenue using Incentives to deliver Innovation and Outputs. The Authority also published a 'Handbook for implementing the RIIO model' ("**RIIO Handbook**") which provides a comprehensive explanation of all elements and principles of RIIO.

85. RIIO was designed to apply to all four energy network sectors (gas and electricity transmission and distribution), but acknowledging that variations would arise across sectors in how the principles were applied. The first RIIO price controls for gas and electricity transmission and gas distribution took effect in 2013, and accordingly, the Authority and DNOs have had opportunities to learn from the process in the design and implementation of the first RIIO price control for electricity distribution (RIIO-ED1).

86. The following paragraphs set out the principles and main features of the RIIO model; the building blocks of how allowed revenues are set under RIIO; and makes some observations on lessons learned by the Authority and DNOs from applying the RIIO model prior to RIIO–ED1.

87. A chronology of the work undertaken in developing RIIO-ED1 is attached as Annex 2.

Principles of RIIO

88. The overriding objective of the RIIO model is to encourage energy network companies to:

(a) play a full role in the delivery of a sustainable energy sector

(b) deliver long-term value for money network services for existing and future consumers

89. These objectives are of course interrelated. In particular, to meet the demands of moving to a low carbon economy there needs to be significant investment in the networks. In planning this investment DNOs need to demonstrate to consumers that the latter are getting value for money over the longer term.

90. Some of the major changes between RPI-X and RIIO are:

(a) Increased role of stakeholders in the process. DNOs are expected to engage proactively with consumers and other stakeholders on an ongoing basis.

(b) Increased transparency and predictability. The review results in a clear 'contract' of what the companies are required to deliver. The framework for the review is developed (and consulted upon) early. Company business plans have been published for the first time, and consulted and discussed with stakeholders.

(c) Extended price control period from 5 years to 8 years. This enhances companies' abilities to manage more effectively the uncertainties they face in the move to a low carbon economy, promotes longer-term thinking and encourages network companies to identify ways of delivering better value for money over the longer term. It also allows the companies more scope to realise the benefits of initiatives such as innovation.

(d) Clearly defined outputs that the companies have to deliver, reflecting expectations of existing and future consumers. These outputs fall into six primary output categories (customer satisfaction; reliability and availability; safety; conditions for connection; environmental impact and social obligations). The outputs were developed in consultation with stakeholders and are set out in a strategy document early in the RIIO

process in order to inform the business plans (see below). DNOs are held to account on their output delivery.

(e) The companies submit business plans, rather than cost forecasts as was previously the case. These plans explain what a company intends to deliver for consumers over time and how, and hence what revenue it needs. These plans are based on the Authority's strategy document, although companies can seek to justify alternatives. The onus is on network companies to justify their view of required expenditure. They are 'public facing' documents, which the companies are expected to use and maintain throughout the price control period. Companies have to demonstrate how stakeholder engagement has been taken into account in their business plans and provide robust reasons for any failure to address stakeholder concerns.

(f) Proportionate treatment and fast-tracking. The business plans are initially reviewed with a view to assessing the level of scrutiny required. Elements of a company's plan that are deemed to be particularly high quality may receive lighter touch regulatory scrutiny. If a plan is judged by the Authority to be of sufficiently high quality and provides good value overall, it is considered for fast-tracking. This means the business plan is accepted as submitted and the company's price control review is concluded early. This plainly incentivises the companies to submit their best business plan early in the process. Fast-tracking provides reputational benefits to the DNO (recognising that price controls are a "repeated game") and enables the DNO to start preparing for the forthcoming price control early (for example, by negotiating contracts). It also encourages companies to reveal information earlier in the process which in turn can drive efficiencies and improve proposals for delivery from the companies remaining in the process. This staged price control process under the RIIO model draws out information from DNOs, which can be taken into account by the Authority to refine its decision-making based on evidence as the process continues.

(g) Innovation. Many elements of the RIIO framework encourage the companies to innovate: such as well justified business plans with long-term justifications, longer price control periods and clear outputs to deliver. However, recognising that the incentives in the price control may not be sufficient to deliver the type and scale of innovation needed to deliver a sustainable energy sector, RIIO also includes a time-limited innovation stimulus which provides funding for research and trials. These stimulus-packages built on the DPCR5 innovation mechanisms and are included in RIIO-ED1 (as with RIIO-T1 and GD1).

(h) Financeability. The RIIO framework, in accordance with to the Authority's duty "to have regard to the need to secure that licence holders are able to finance the activities [which are the subject of obligations on them]" sets out clear principles that efficient network companies should be able to secure financing in a timely way and at a reasonable cost in order to facilitate the delivery of their regulatory obligations. This is in the interests of consumers. These principles are designed to ensure that the framework does not provide excessive returns, reward inefficiency or 'bail-out' a company that has encountered financial distress as a result of its own behaviour. Principles include i) a longer-term view of financeability; ii) allowed return based on the weighted average cost of capital (WACC); iii) cost of debt element of the WACC based on a long-term trailing average, providing a good estimate of the cost of debt and updated annually within the price control; iv) asset lives underpinning the depreciation policy to reflect expected economic life; vi) an onus on companies to manage short-term requirements and provide equity where necessary, and vii) return on regulatory equity (RORE) analysis to check if the price control package fits together appropriately.

Setting allowed revenues under RIIO

91. As with the RPI-X framework, RIIO is used to set a revenue cap whereby the Authority determines the maximum revenue a DNO can collect from its customers over the duration of the price control. Allowed revenues are set to

cover all aspects of a DNO's business except for services directly remunerated by customers (such as some types of connections to the network and legacy metering).

92. The price control is set using a 'building block' approach to assess allowed revenues, incorporating incentives to encourage network companies to deliver outputs and value for money over the long term.

93. As was the case under the previous regime, allowed revenues comprise:

(a) Remuneration for efficient expenditure broken into two components: 'fast' and 'slow' money. Slow money is remunerated as if it was capital expenditure and hence is incorporated into the company's Regulatory Asset Value (RAV) and depreciated over time. Fast money, by contrast, is remunerated as if it was operating expenditure and is recovered in the current price control period;

(b) An allowed profit (determined as WACC multiplied by average RAV); and

(c) A tax allowance.

Together, these determine the base revenue, to cover expected efficient costs.

94. Three types of adjustments are made to reflect the company's performance. These relate to:

(a) output incentives,

(b) efficiency incentives, and

(c) an innovation stimulus during the control period.

95. Adjustments are made during the control period for specified uncertainties that are considered to be outside the company's control but will have a significant impact on costs of delivery (e.g. compensation for changes in general price inflation in the economy) and changes to financial parameters that are updated during the period (e.g. annual adjustment to the cost of debt, pension

adjustments). The allowed revenue is also adjusted each year for any over or under-recovery of revenues by the DNO in the previous year.

96. Each of these above four adjustments is described in further detail below.

Output incentives

97. In principle, output targets, cost allowances for delivering those targets and incentives around beating or not meeting those targets should be set in the round to reflect the level of output (service) that end consumers of the service are willing to pay for, taking into account the range of potential overall returns to the companies.

98. Determining willingness to pay of current and future consumers is not an exact science. This inevitably requires the exercise of judgements as to whether the evidence points to the outputs framework broadly providing value for money for consumers and as to whether the structure of the incentive reflects the degree of confidence in the underlying evidence.

99. The incentive schemes are designed such that companies that outperform, i.e. that efficiently over-deliver what their consumers value, earn above normal returns and those that underperform, i.e. fail to efficiently deliver what their consumers value, earn below normal returns. This reflects the aim for the RIIO control to effectively mimic what would be observed in dynamic competition in markets.

100. Under RIIO, companies are incentivised to take responsibility for delivering outputs at value for money. This requires them to demonstrate that outputs, and the costs of delivering them, are providing what their customers want, and to engage with their stakeholders to inform their understanding. This in turn requires the Authority to provide a clear regulatory framework early enough in the process for such engagement to take place.

101. In order to facilitate this, Ofgem needs to make and commit to strategy decisions much earlier in the price control review than under RPI-X regulation. Commitment to these decisions is important for the business plan engagement process to be considered credible by both DNOs and their

stakeholders. Retaining commitment during the process also sends important signals for future price control reviews. This does not mean that once strategy decisions are made they are set in stone irrespective of later evidence. Price control reviews are a discovery process. Where there are good reasons to do so in the consumer interest, changes are made, but only after taking into account a range of stakeholder views and the need to retain confidence in the overall process which itself benefits consumers.

102. The six primary output categories reflect the broad role that the network companies will play in delivering the RIIO objectives. A variety of incentive mechanisms are used to encourage companies to deliver these outputs.

103. In addition to these primary outputs, the RIIO model includes secondary deliverables, which are leading indicators of companies' performance and are intended to ensure that they take a long-term perspective to managing their networks.

104. If price controls were focused only on the delivery of primary outputs, network companies may be encouraged to deliver these at the lowest cost during the eight-year price control period, potentially at the expense of measures that could help reduce the costs of delivering primary outputs over the longer term. To protect against this, the Authority expects the network companies to focus on the longer term and consider whether it is appropriate to include costs in their business plans that are related to delivery of primary outputs in future price control periods and to long-term value for money.

105. Secondary deliverables hold companies "to account" to (a) the management of network risk and hence long-term delivery of primary outputs; and (b) the anticipation of future needs. For example, asset health indicators reflecting risk and criticality may be a potential secondary deliverable target. Secondary deliverables are not the 'ends' relating to consumer experience of network services but are the longer term 'means to the end'. They are needed to ensure delivery of primary outputs over time and that long-term value for money is not put at risk.

Efficiency incentives

106. The business planning process and the Authority's assessment of base revenue in the price control review are key parts of the framework, designed to encourage network companies to seek to deliver outputs (and secondary deliverables) that are lowest cost over the longer term. The plan provides a helpful and reasonable basis on which to make assessments of forecast efficient costs. However, the Authority does not expect network companies to deliver exactly against their plans over the eight-year price control period. Rather, network companies are expected to evaluate the optimal way of delivering on an ongoing basis, taking account of new information, learning and potential changes in circumstances over time. It is in this context that the RIIO framework provides specific incentives for DNOs to seek out, over the duration of the price control, delivery solutions that provide better value for existing and future consumers.

107. The Information Quality Incentive ("**IQI**") is a mechanism in the RIIO framework designed to encourage companies to submit accurate expenditure forecasts during the price control review, and then spend efficiently during the price control period. More accurate expenditure forecasts enable the Authority to benchmark the DNOs comparatively and set efficient cost allowances for the price control period. IQI efficiency incentives, together with the efficient cost allowances, incentivise the DNOs to spend efficiently through RIIO-ED1. This enables the Authority to identify further efficiencies which can be recognised in future reviews. The Authority expands on this

Innovation incentives

108. Innovation is key to enabling network companies to deliver the objectives of the RIIO model, namely to play their role in the delivery of a sustainable energy sector and to deliver long-term value for money for existing and future consumers. Such innovation could take many forms, including deployment of new "smarter" technologies and/or the implementation of new operational processes and commercial arrangements (such as demand side management).

109. Under the RIIO model, companies are encouraged to innovate by longer-term, outputs-led, incentive-based, ex ante price controls which give companies commitment around the potential rewards that they can earn from successful innovations and a commitment not to penalise them for unsuccessful innovations. It is also driven by stakeholder engagement, clearly defined outputs and the ability to justify expenditures over periods longer than the price control under review.

110. However, RIIO recognises that there are some circumstances where the benefits of innovation are uncertain, or unlikely to accrue to the network company. To take account of this, the framework includes an innovation stimulus package which provides partial financing for innovation related to delivery of a sustainable energy sector. This builds in the successful Low Carbon Networks Fund in DPCR5. Companies are required to share the learning from trials and projects funded through the stimulus with companies across the sector.

Uncertainty mechanisms

111. While a longer control period can encourage innovation, it can also potentially increase the uncertainties around future DNO outputs and expenditure requirements. The RIIO model includes mechanisms to ensure that risks are borne by the party best able to manage them efficiently. This includes setting out mechanisms under which DNOs' revenues are adjusted; the potential for disapplication of the price control; and a tightly-defined mid-period review of output requirements.

The RIIO-T1 and GD1 reviews

112. The RIIO model was first implemented in the RIIO-T1 and GD1 price control reviews in the gas and electricity transmission sector and the gas distribution sector respectively. These reviews started in April 2011 and were implemented from 1 April 2013.

113. The Authority drew on the experience it had gained from those processes to inform its approach to the design and implementation of RIIO-ED1 as

described below. The Chronology attached in Annex 2 provides further details of the Authority's process.

RIIO-ED1

114. The RIIO-ED1 price control set the outputs that the 14 DNOs need to deliver for their consumers and the associated revenues they are allowed to collect during RIIO-ED1. This period runs for the eight years, from 1 April 2015 to 31 March 2023.

115. There were three stages to the RIIO-ED1 price control review: Stage 1: Strategy consultation and decision ("strategy decision"); Stage 2: Business plans and proportionate treatment ("fast-track"); and Stage 3: Revised business plans and detailed assessment ("slow-track"). Each is outlined briefly below.

Stage 1: Strategy decision

116. In Stage 1, the Authority developed the key elements of the regulatory framework ("strategy") for RIIO-ED1 so that DNOs were in a position to develop, consult upon and justify business plans for the RIIO-ED1 period which met the needs and requirements of existing and future consumers at good value.

117. The strategy was developed over an eight month period, with input from a range of stakeholders, including consumer and environmental groups, industry and government, as well as the DNOs. Eight policy specific working groups[43] were established (comprising DNOs and other stakeholders), together with a Price Control Review Forum (comprising a broad range of stakeholder representatives) and a Consumer Challenge Group.[44] The Authority consulted on the RIIO-ED1 strategy in September 2012 **[NPg/2/B/3]** and published its Strategy Decision in March 2013 **[NPg/1/B/7]**.

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[43] Flexibility and capacity; Environment; Innovation; Reliability and safety; Connections; Customer and social issues; Finance; Cost assessment.

[44] This comprised a range of consumer experts, to act as a 'critical friend' to Ofgem and provide an external perspective on whether elements of the price control settlement were in the best interests of existing and future consumers.

118. The Strategy Decision addressed: the outputs that companies would be expected to deliver and the associated incentive mechanisms; the process for assessing the companies' business plans; proposed mechanisms for handling uncertainty; proposed mechanisms for encouraging innovation; and Ofgem's approach to financeability. It set out the five core criteria against which the business plans would be assessed, namely: whether the DNO had followed a robust process; whether its plan delivered the required outputs; whether its costs of delivering the outputs were efficient; whether its proposed financing was efficient; and whether the plans dealt well with uncertainty & risk.

119. The Authority confirmed that it would retain its 'toolkit" approach to cost assessment, similar to that used in RIIO-T1 and GD1, and would apply it at both fast track and slow track.

120. For RIIO-T1 and GD1, the Authority had adopted a four stage assessment process. At fast-track it had provided licensees with high level feedback on their submitted plans (termed the 'initial sweep') and gave them an opportunity to improve their plans before taking its decision on proportionate treatment. In applying this approach in the RIIO-T1 review the Authority allowed the two Scottish transmission companies to address resolvable issues to their plans to enable them to meet the standards necessary for fast tracking.

121. For RIIO-ED1, however, the Authority made clear in the Strategy Decision that it expected the DNOs to have learned, from observing the RIIO-T1 and GD1 process, what was expected from them at the fast-track stage under RIIO. It therefore made clear that it believed that *"a three stage assessment process [was] sufficient and there [was] therefore no need for an additional 'initial sweep' stage*.**" [NPg/1/B/8/page 391/para. 2.19]**

Stage 2: Fast track

122. The DNOs produced business plans on the basis of the Strategy Decision and submitted them to the Authority on or before 1 July 2013 for fast track assessment. The Authority also required the DNOs to publish their business plans on their websites, providing a significantly greater amount of information for public scrutiny than in previous electricity distribution price control reviews.

The Authority sought views on these plans in its open letter on RIIO-ED1 business plans **[RDB/tab 5]**.

123. The Authority assessed the submitted plans in accordance with its approach in the Strategy Decision and applied a traffic light system to identify those elements of each DNO's plans that were acceptable (green) and those that required further attention (amber and red). This included a detailed comparative cost assessment using the toolkit approach. The Authority used three comparative cost assessment models, analysing costs at a total expenditure (totex) level using two different totex models and on a cost activity level basis using disaggregated activity-level modelling. It used 13 years' of data including available DPCR5 data and DNO cost forecasts.

124. The Authority used three models in recognition of the fact that there is no definitive answer for assessing comparative efficiency. It expected the models to yield different results. There are advantages and disadvantages to each approach. Totex models internalise operational expenditure (opex) and capital expenditure (capex) trade-offs and are relatively immune to cost categorisation issues. They give an aggregate view of efficiency. The bottom-up, activity-level analysis has activity drivers that can more closely match the costs being considered.

125. Having assessed the plans in the round, the Authority published its assessment on 22 November 2013 **[NPg/1/B/10]**. It proposed that Western Power Distribution's ("**WPD's**") four licensees be fast-tracked, recognising that WPD's business plans were, overall, of sufficiently high standard that it was in the interest of consumers to accept its submitted plans in full.

126. WPD was the only DNO group to score "green" in all assessment categories. The other DNOs' plans scored green in some areas, but had areas requiring further work and so were consequently not considered suitable for fast tracking.

127. On 8 November 2013 the CC issued its provisional determination for Northern Ireland Electricity ("**NIE**") **[RDB/tab 6]** in which it proposed a cost of equity allowance and resultant overall weighted average cost of capital ("**WACC**")

materially lower than that proposed by the DNOs (which in turn were broadly similar to those set in the previous RIIO reviews). This prompted the Authority to re-consult on its approach to assessing the DNOs' cost of equity allowances, which it did on 6 December 2013 **[RDB/tab 7]**. In its decision of 17 February 2014 **[RDB/tab 8]** it concluded that it should reduce the baseline assumption for an efficient cost of equity and invited WPD to accept a specified reduction as a condition to being fast tracked, to which WPD agreed.

128. On 28 February 2014 the Authority decided to fast track the WPD DNOs **[RDB/tab 9]**. It gave notice of its proposal to modify the WPD DNOs' licences so as to implement its decision in accordance with section 11A(2) EA89 on **[RDB/tab 10]** on 28 March 2014. In the light of responses it received to this consultation and its earlier RIIO-ED1 consultations, it decided to proceed with the modification as consulted upon, subject to minor drafting corrections **[RDB/tab 12]** No party appealed this decision.

129. The potential to be fast-tracked appears to have been achieved its intended purpose in that, in the view of the Authority, the quality of the DNO submissions showed a marked improvement to that of previous price control submissions. All plans scored "green" in at least one assessment category and demonstrated strong stakeholder engagement. Further, the plans showed efficiency savings of more than £2 billion compared to previous forecasts **[NPg/1/B/10/page 1]**.

Stage 3: Slow track

130. In Stage 3, the 10 DNOs that were not fast tracked were required to submit revised business plans in March 2013. DNOs published their modified plans on their websites and the Authority consulted on them **[RDB/ tab 11].** Consistent with its Strategy Decision the Authority focussed its attention at slow track on those elements of the DNOs' plans that it assessed to be in the amber or red categories at fast track.

131. The slow track DNOs' revised plans included justifications and output packages at lower cost, with a £700m reduction in forecast expenditures

versus their fast-track plans.[45] Most DNOs did not change their business plans for elements that were rated green at fast-track.

132. None of the slow track companies was judged to have demonstrated that their proposed costs (including their proposed savings from the use of smart or innovative tools and techniques) were efficient at fast track. Consistent with the Strategy Decision, these were therefore assessed in detail. The assessment included a further comparative benchmarking exercise. This involved assessing the Authority's view of efficient costs and then applying IQI interpolation (75% of the Authority's view of efficient costs and 25% of the DNO's cost forecast) to reflect the fact that the Authority does not have perfect information.

133. As part of its submission to the CMA, NPg included a report by Frontier Economics ("**Frontier**") which contains a description of the Authority's cost assessment framework **[NPg/5/B/1/pages 107-108]**. The Authority has reviewed this report and though for the most part it is factually correct, there are some minor errors and incomplete descriptions, as set out in the attached Annex 3.

134. On 30 July 2014, the Authority consulted upon its Draft Determinations for the slow track DNOs based on its assessment of their resubmitted plans **[NPg/1/B/12]**.

135. In response to the Draft Determinations, some respondents claimed that the changes made to the assessment process between the fast-track and slow-track processes provided WPD with an unfair advantage at RIIO-ED2. The Authority disagrees with this contention. It estimates the financial benefit to WPD of being fast-tracked at around £250m **[NPg/1/B/15/page 978/para. 2.13]**. The Authority considers that this £250m benefit is reasonable when balanced against the broader benefits of the fast-tracking approach (better initial business plans, a further £700m improvement across the sector between fast- and slow-track, and significantly better data for benchmarking DNOs at slow-track), which are greater than the benefits available to WPD.

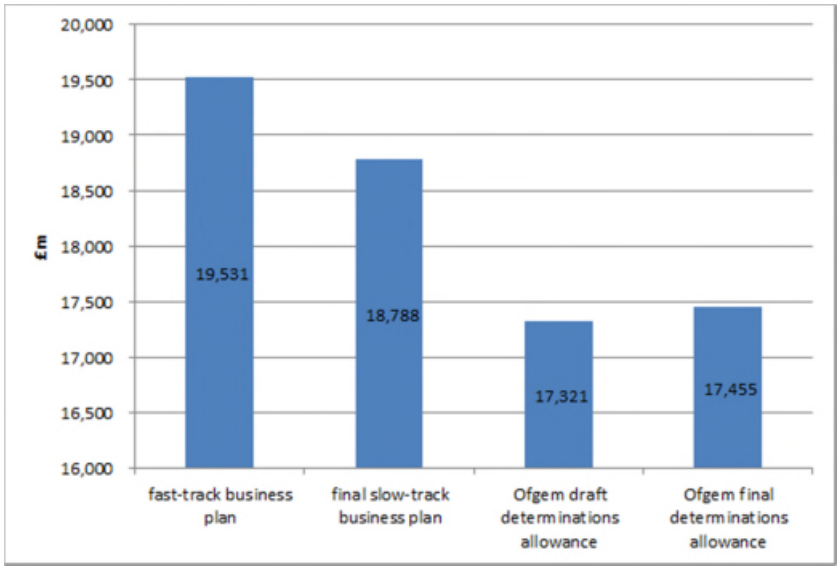
[45] All DNOs other than NPG reduced their cost proposals relative to their fast track plans.

The Authority considers that the fast-track process has unlocked substantial value for consumers that would not have been possible otherwise.[46]

136. On 26 September 2014 **[RDB/ tab 16]** the Authority consulted informally on its proposed licence modifications and on 28 November 2014 it published its Final Determinations for the slow track DNOs **[NPg/1/B/15]**.

137. Overall, the Authority considers its Final Determinations are challenging for the DNOs to achieve, but fair, and represent good value for money for customers. They represent a £1.3bn (7%) reduction on the expenditure forecasts in the DNOs' slow-track plans. This is an 11% reduction from the fast track plans and 1% higher than Draft Determinations. This is shown in Figure 1.

Figure 1. Slow-track DNO forecast and allowed total expenditures (2012-13 prices).



[46] Further, as explained at **[NPg/1/B/15/ paras. 2.16 and 2.17]** the Authority does not consider that fast tracking provides WPD with an unfair prospective advantage for RIIO-ED2.

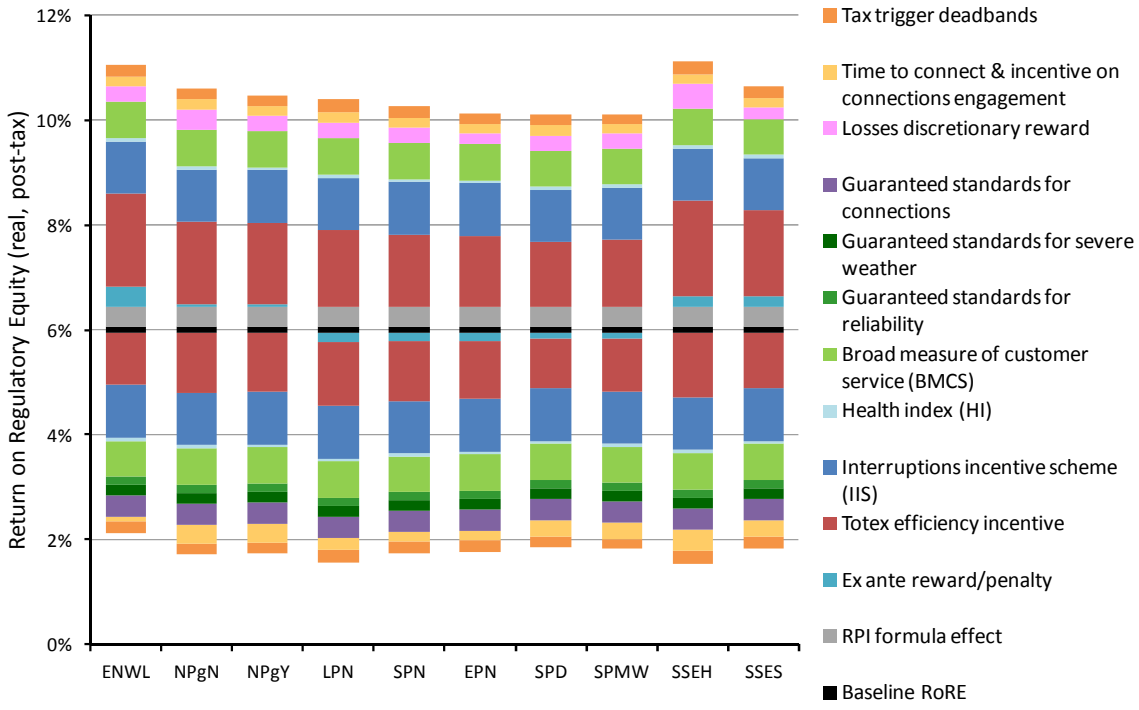
Table 1 below sets out the DNOs' total base revenues for the RIIO-ED1 period upon which allowed revenues are built.

Table 1. Base revenues for slow-track DNOs in the DNO licences.

£m 2012/13 prices	ENWL	NPg	UPKN	SPEN	SSEPD	Total
Final Determinations without updated pension deficit funding allowances	2,892	4,598	10,027	5,156	5,864	28,539
Final Determinations with updated pension deficit funding allowances	2,887	4,559	10,092	5,250	5,862	28,650
Disposals and DRS9 Corrections (as per 17 December 2014 letter)	-1	0	2	10	-12	-1
Further two corrections	1	0	0	0	7	8
Base revenues included in the licence	**2,887**	**4,559**	**10,094**	**5,260**	**5,857**	**28,656**

138. The Authority also assessed the Final Determinations as a package, and their impacts on DNOs' financeability by considering plausible ranges of Return on Regulatory Equity ("**RoRE**") for each slow track DNO for the RIIO-ED1 period, as described in Figure 2. The RoRE ranges shown in the chart are broadly consistent with the Authority's Strategy Decision that outperforming DNOs could potentially earn RoRE above 10% while RoRE for underperforming DNOs could be below the cost of debt.

Figure 2. Ranges for RoRE over RIIO-ED1 period



139. In the Authority's view, this analysis indicates a package of risk and reward calibrated to provide strong incentives for DNOs to deliver the outputs existing and future consumers need and require at efficient long-term cost. The Authority does not consider that DNOs will earn rates of return in excess of the fair rate of return (cost of capital) included in the Final Determinations, or as high as or higher than the returns achieved in the past. As already mentioned, the RIIO-ED1 Final Determinations are challenging for DNOs. The Authority has set tight cost allowances, an efficient cost of capital, and has tightened incentive mechanisms in a number of ways compared to DPCR5. It has also set an incentive in the licence under which DNOs suffer a penalty in RIIO-ED2 if they fail to deliver specific improvements to their asset base, without justification **[NPg/1/B/22/section "CRC 5D. Assessment of Network Asset Secondary Deliverables"]**. The potential scope for outperformance in RIIO-ED1 has also been reduced relative to DPCR5 because the Authority has had better access to information due to the fast-track process.

140. On 17 December 2014 the Authority gave notice of its proposal to modify the slow track DNOs' licences so as to implement its Final Determinations in

accordance with section 11A(2) EA89 **[NPg/1/B/19]**. Taking account of all of the evidence obtained during the RIIO-ED1 process, up to and including responses to the final round of consultation, on 3 February 2015 the Authority decided to proceed with the modifications set out in the notice, subject to the correction of minor errors as referred to in Table 1 **[NPg/1/B/22]**.

141. While the Final Determinations were the conclusion of the RIIO-ED1 price control review for each of the slow-track DNOs, where certain elements had not changed since the Strategy Decision, these were not explained again in detail. This is why the modification notice referred to both documents. There are some instances where, in the process of developing Draft and Final Determinations, some elements changed from the position set out in the strategy decision. Where this was the case the Authority made it clear in the determinations, and consulted on its reasons for doing so. It also noted in the Strategy Decision that certain values, such as the financial values for incentive caps and collars could not be set until Final Determinations, as they were based on the DNOs' base revenues.

142. The modifications comprise a suite of interrelated licence conditions which incorporate a detailed executable financial model (the Price Control Financial Model or PCFM) and related PCFM Financial Handbook. These facilitate annual updates of allowed revenues (the "**annual iteration process**") to enable specified financial adjustments to be made as close as reasonably practicable to associated expenditure rather than to be logged up for treatment only at the end of the price control period.

PART IV: GROUND 1 – SMART GRID BENEFITS

Introduction

143. This ground of NPg's appeal is a challenge to the Authority's approach to assessing the extent of "smart grid benefits" ("**SGBs**"), that is net cost savings which DNOs could reasonably be expected to achieve over the price control period in respect of smart grid technologies and other forms of technological innovation.

144. At the outset, and before responding to NPg's allegations, it is convenient to summarise the Authority's position on this ground of appeal, as follows.

(a) In respect of the essentials of the *process* the Authority undertook:

(i) The Authority identified from the outset that SGBs would be a particular area of its focus. The Authority also made clear from the outset that the slow track assessment process would involve a materially more detailed assessment of properly allowable costs than under the fast track assessment process;

(ii) The DNOs were aware that the fast track assessment process would be an "in the round assessment", as contrasted with a more detailed quantitative assessment at the slow track stage.

(iii) At the slow track stage:

(1) A range of reputable external data sources indicated that the DNOs had, as a whole, underestimated the level of realistically achievable SGBs across their business plans.

(2) The Authority, having identified these sources as indicating an understatement of SGBs, identified proposed additional reductions to DNOs allowable revenues.

(3) Following representations from the DNOs, criticising the Authority's reliance on the external data, at the slow track Final Determination stage the Authority maintained its

reliance on those sources (together with DNOs' own data) as indicating the *fact* of an underestimation of SGBs but relied only on the DNOs' own data in order to *quantify* the extent of that underestimation and refine the allocation of SGBs between DNOs. Thus, DNOs' own data and business plans also confirmed the fact of the underestimation.

(4) This constituted a rather conservative approach to the identification and quantification of the SGBs which DNOs could reasonably be expected to achieve, since the quantification of total SGBs was a product of DNOs' own internal data and business plans. In calculating the total, the Authority isolated the maximum saving identified by any DNO in their respective business plans under four cost categories in which SGBs could reasonably be expected to arise. The Authority then took the sum of those potential savings across all four cost categories. Given that SGB savings identified by one DNO should be achievable by all DNOs (though the specific solution applied may not always be the same), the sum of potential savings was then multiplied to reflect the total savings across all DNOs. The Authority adopted measures, as part of this process of identifying total SGBs, to ensure that there was no double counting of SGBs already included in DNOs' forecast cost savings.

(5) This analysis produced a total sum of SGBs which could reasonably be expected to arise across the price control period. This total saving was then allocated between DNOs proportionately, taking into account the "embedded" SGBs already recognised by the Authority within each DNO's business plan, in order to arrive at the total adjustment to be applied to each DNO's allowable

revenues properly to reflect the SGB savings which that DNO could be expected to benefit from over the price control period.

(b) In respect of the essentials of the *analysis* the Authority undertook and its *rationale*:

(i) As mentioned above, by reference to reliable data including DNOs' own reductions to the allowances they were claiming by way of embedded benefits, the Authority concluded that all DNOs had under-estimated the extent of achievable SGBs in each of their business plans.

(ii) This could be seen by (a) the total SGBs indicated by a range of external data sources and (b) comparative analysis of DNOs' own business plans.

(iii) It followed from the conclusion at (i) above that the Authority's assessment under the slow-track assessment process required it to recognise SGBs which would flow to DNOs over and above those already recognised as embedded within their business plans.

(iv) In the proper discharge of its regulatory duties, including having due regard to the consumer interest, the Authority was obliged properly to reflect in its price control decisions its best view of the proper extent of savings that would flow to DNOs from SGBs.

(v) The consumer interest in ensuring that the full range of SGBs was reflected in the price control regime was heightened by the fact that smart solutions giving rise to SGBs have been developed through the use of substantial amounts of *public* (i.e. consumer) funding both channelled to DNOs through schemes such as the Low Carbon Networks Fund and as a matter of public funding of the smart metering programme.

(vi) The adjustment we made to DNOs' allowances in order to ensure that the proper extent of achievable SGBs were reflected in their cost assumptions is equivalent to, on average, a further 0.2% efficiency saving per year (i.e. a shift in the efficiency frontier). This effective shift in the efficiency frontier reflects technological innovation not business-as-usual efficiency gains and therefore the Authority's mode of assessment of these smart savings reasonably needed to differ from its general approach to business as usual efficiency savings.

(vii) The assessment of the SGBs which could reasonably be expected to arise over the price control period was one element of the Authority's overall view of efficient costs. In determining a DNO's allowable revenue the Authority interpolates its own assessment with the relevant DNO's assessment in the proportion of 75% the Authority's view and 25% the DNO's view (as set out in its submitted costs). The application of interpolation is designed to allow for the fact that the Authority reaches its overall assessment of the costs that a DNO can reasonably be expected to face over the price control period on the basis of imperfect information which may not take account of all relevant data and considerations.

145. The background on the definition of SGBs is as set out by NPg at paragraphs 6.7 – 6.11, save that the Authority does not agree that over the period of RIIO-ED1 smart grids are primarily or necessarily concerned with low carbon technologies ("**LCTs**") (see for instance **[NPg/2/B/4/paras 10.2 – 10.4**] and [**NPg/1/B/8/paras 3.31 – 3.32**]. One of the flaws in NPg's approach to SGBs was that it was too much focused on innovation connected to LCTs and failed adequately to show consideration of other forms of smart grid/innovative technology.

Process adopted and criticism of that approach

Summary of the complaint

146. The Authority does not agree with the complaint set out at paragraphs 2.4 to 2.7 that it adopted an unjustified, disproportionate and discriminatory approach in Final Determination. As set out in paragraph 141 above and in more detail below:

(a) The Authority's approach was justified and proportionate given the importance of securing benefits for consumers reflecting the smart grid benefits that in the Authority's expert judgment, and based on a range of sources of evidence, could be expected to arise over the course of RIIO-ED1;

(b) The Authority's approach developed during the course of the price control process as it properly took account of representations, comments and suggestions from DNOs and other relevant parties and considered new information supplied to it or obtained through the course of the consultation process;

(c) The Authority had indicated from the outset both the importance that it attached to SGBs and the fact that the slow track assessment process would involve significantly more scrutiny of plans than at fast track.

Description of the process adopted

147. In respect of the description of the Authority's approach to RIIO-ED1 as set out by NPg at paragraphs 6.12 – 6.13, the Authority's response is as follows:

(a) The Authority agrees that the DNOs were incentivised to produce well-justified business plans by the fast track/slow track assessment system. This was explained at paragraph 1.2 of the Authority's "Strategy Decision for the RIIO-ED1 electricity distribution price control – Business plans and proportionate treatment" dated 3 March 2013 (the "**Strategy Decision – Business Plans**") [**NPg/1/B/8/para. 1.2**], which stated: "*The quality of the [business] plan, the robustness of the data within it, and how well it is justified, will influence the degree of*

regulatory scrutiny we apply during the review ('proportionate treatment')."

(b) The DNOs were assessed at the fast track stage using a traffic light system in respect of five core business plan assessment criteria, namely:

(i) Criterion 1. "Process: Has the DNO followed a robust process?";

(ii) Criterion 2. "Outputs. Does the plan deliver the required outputs?";

(iii) Criterion 3. "Resources (efficient expenditure): Are the costs of delivering outputs efficient?";

(iv) Criterion 4. "Resources (efficient financing): Are the proposes financing arrangements efficient?"; and

(v) Criterion 5. "Uncertainty & risk: How well does the plan deal with uncertainty and risk?"

(c) Any DNO which received a green light in respect of all these criteria was to be considered for early approval at the fast track stage. This was explained at paragraph 1.3 of the Strategy Decision – Business Plans:

> *In some cases, where a DNO produces a very high quality business plan, we will consider whether it is appropriate to conclude their price control process early ('fast-tracking'), thereby significantly reducing the level of scrutiny the DNO is to undergo*.

(d) Any DNO which failed to receive a green light for one or more of the five criteria was to be assessed on the slow track. The rigorous test for fast-tracking and the degree of scrutiny which would be applied to slow-tracked DNOs was explained in paragraph 2.2 of the Strategy Decision – Business Plans:

It is essential that a DNO performs well in each and every section of the core assessment criteria. It is therefore possible that no DNO will be fast-tracked if our assessment is that none have met the required standard. Conversely, DNOs whose business plans are not of a high enough quality will receive a higher degree of regulatory scrutiny and are likely to be required to make substantial improvements to their plans following our initial assessment.

(e) The DNOs would also have been aware of the detailed level of scrutiny that the Authority applied in assessing cost efficiencies in the slow track RIIO price control processes for electricity and gas transmission and gas distribution, which had already concluded by February 2013.

(f) The Authority submits that it is clear that the DNOs ought to be have been aware from the outset that the slow track assessment process would (compared with the fast track process) entail additional work by DNOs on their business plans and a significantly higher degree of regulatory scrutiny by the Authority, with particular focus on the areas of most concern.

(g) The Authority does not agree that DNOs could reasonably have concluded that SGBs would not be the subject of quantitative analysis during the slow track assessment process other than as part of a more general benchmarking process. The importance of SGBs as a standalone consideration was identified at the outset in the Authority's published strategy decision documents (March 2013), including in the following extracts:

(i) Strategy Decision – Overview [**NPg**/**1/B/7**]:

(1) Under the heading "*Smart grids solutions*", at paragraphs 2.13 – 2.14, "*Smart grids technology and associated contractual arrangements with customers and generators may offer DNOs a more cost effective way of resolving*

constraints on the network than investing in more assets. They may also provide the DNOs with more flexibility especially where they are unsure of longer term demand. The Smart Grid Forum (SGF), co-chaired by Ofgem and the Department of Energy and Climate Change (DECC), has continued to work to understand what drives the value of smarter solutions and address barriers to their adoption. More information on the SGF is provided in Appendix 3. The LCN Fund is funding trials to assess the potential operation and benefits of smart technologies (including storage) and DSR[47], amongst other things."

(2) At paragraphs 2.16 – 2.17, "*The SGF has looked at whether there might be benefits from rolling out smart grids solutions en masse in RIIO-ED1. Initial cost benefit assessments, combined with the fact that we currently do not fully understand smart grids and the uncertainty around low carbon technology take-up, appear to indicate that a more incremental approach to smart grids is appropriate during RIIO-ED1….Some stakeholders have questioned whether DNOs will be sufficiently incentivised to undertake the cultural change this will require. We set out in the next section how we have designed RIIO-ED1 to ensure this will happen*."

(3) Under the heading "*RIIO-ED1 package*", at paragraph 2.19, "*We expect the business plans to reflect the adoption of smart solutions (including DSR) and the learning from LCN Fund projects where they are cost effective versus conventional solutions*."

(4) Under the heading "*Cost assessment*", at paragraph 6.14, "*Under the RIIO framework the onus is on companies to*

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demonstrate the cost-efficiency and long-term value for money of their business plans. We plan to use benchmarking of historical and forecast data as a means of informing our assessment of the DNOs' forecasts rather than as a mechanistic means of setting allowances. (emphasis added)

(5) Under the heading "*Innovation*", at paragraph 7.1, "*The DNOs are likely to need to innovate if they are to ensure the delivery of a sustainable electricity sector and that their services represent long-term value for money for existing and future consumers. In DPCR5 we introduced the LCN Fund to encourage the DNOs to sponsor projects which trial innovative technological, operating and commercial arrangements to facilitate the transition to a low carbon future. It is widely considered to have significantly improved the DNOs' attitude to innovation, knowledge sharing and collaborative working with third parties. We expect to see the results of learning from LCN Fund projects embedded in DNOs' business plans*."

(ii) Strategy Decision – Outputs, incentives and innovation [**NPg/2/B/4**]:

(1) Under the heading "*Assessing DNO progress in adopting smart grid solutions*" at paragraph 3.21, "*The consideration of smart grid solutions will need to be at the heart of the DNO's business plan if they wish to be eligible for fast tracking. DNOs who fail to consider fully the use of such solutions in their core business risk falling behind our assessment of efficient cost. We expect a well-justified business plan…*"

(2) Under the heading "*Encouraging Innovation*", at paragraphs 10.2 – 10.4, "*Many elements of the RIIO price*

control framework are designed to encourage innovation, for example lengthening the price control period to provide companies with more certainty of the rewards for successful innovation. DNOs have had access to specific funding for innovation in DPCR5 through the Innovation Funding Incentive (IFI) and LCN Fund. We consider the LCN Fund has worked well and it is widely considered to have significantly improved the DNOs' attitude to innovation, knowledge sharing, anticipating the low carbon future and collaborative working with third parties. We therefore expect DNOs to demonstrate clearly throughout their business plans that they have properly considered the use of alternative or innovative techniques in all areas of their business to deliver their outputs more efficiently. We expect to see concrete evidence of learning from IFI and LCN Fund projects being utilised within the DNOs' businesses. We will take account of past and future innovation funding provided to DNOs in setting the efficiency frontier for the period (i.e. we would expect the high levels of innovation funding to date to allow DNOs to achieve results more efficiently)".

(iii) Strategy Decision – Business plans and proportionate treatment [**NPg/1/B/8**]:

(1) In guidance on "*Criterion 3 – Expenditure*":

a. Paragraph 3.23, "*The DNO must clearly set out and explain the costs of delivering its outputs. A well-justified business plan will demonstrate, through clear evidence, that a DNO's costs are efficient*."

b. Paragraphs 3.31 – 3.32, "*We expect DNOs to clearly demonstrate throughout their business plans that they have considered the use of alternative techniques*

(such as innovative technical, operational, commercial and contractual arrangements) in all areas of their business to deliver their outputs more efficiently and reduce costs. We also expect that some of the projects funded under the Innovation Funding Incentive (IFI) and Low Carbon Networks (LCN) Fund will have delivered valuable learning DNOs can use within their businesses. Therefore, we expect to see evidence of this learning (both from their own innovation projects and those of other DNOs) in the development of DNOs' business plans."

(2) Appendix 2, Business plan guidance, under the heading "*Detailing smart grids in business plans*" on page 54, "*We acknowledge that DNOs may struggle to identify the impact of smart grids on each line item in an expenditure category, particularly for the latter years of the price control. However, we would expect that the overall expenditure they request takes account of any net benefits which their costs benefit analysis indicates smart grids can provide. Consequently, the expenditure totals in each business plan data table should reflect the costs and benefits of implementing their smart grid strategy… DNOs should take a similar approach when they are including the benefits of innovative solutions which would not be deemed as smart grid solutions. The costs and benefits should be included in the expenditure totals in each data table and the commentaries should provide the detail on what innovation will be deployed*."

(iv) The DNOs were asked to complete cost tables to be submitted with their business plans which also highlighted the need specifically to consider SGBs, see data tables CV103 and S1 in NPGN_BPDT_2014 [**NPg/5/C/10**].

(h) At fast track stage the assessment of SGBs took the form of a qualitative review of the DNOs' business plans. As set out above, the DNOs were aware that the assessment of their business plans would be lighter touch at the faster track stage than under the slow track process. The Authority does not agree that it was intended that SGBs would only be assessed throughout the entire process by way of qualitative assessment.

(i) In NPg's case, as set out at paragraph 6.34, it received an amber light at the fast track assessment stage for criterion 3, cost efficiency. The overall assessment of NPg's business plan was described as follows at paragraph 1.1 of Appendix 4 (NPg) to the Assessment of RIIO-ED1 business plans [**NPg/2/B/5**] ("**The NPG Fast Track Assessment**"), "*NPG's plans are…very well developed and presented, demonstrating high quality stakeholder engagement. However, at this stage, we are not convinced that its proposed expenditure allowances are efficient*." (emphasis added).

(j) The Authority agrees that the quote set out in the first sentence of paragraph 6.35 is accurately reproduced but the quote continues, as highlighted in the previous paragraph above, to emphasise that the Authority had serious reservations about NPg's business plan at fast track stage. As the second worst-performing DNO in respect of cost efficiency, the Authority does not agree that NPg produced a lean and challenging business plan in that crucial respect.

The Authority's refinement of its approach

148. The Authority does not agree with the characterisation, at paragraph 6.14, that it adopted "*three significantly different approaches*" to the assessment of SGBs. In particular:

(a) The difference in approach that the Authority would take between the fast track and slow track assessment processes was clearly signalled in the Authority's Strategy Decision documents of March 2013, as set out above.

(b) At the fast track stage the Authority sought to assess DNOs' business plans/costs on an "in-the-round", light touch basis. It was of course this lighter touch assessment which facilitated a faster determination.

(c) For those DNOs not approved at the fast track stage, as was made clear from the outset, the slow track assessment process would require them to submit revised business plans and would involve considerably more detailed scrutiny of their proposals, including detailed quantitative analysis.

(d) For slow-tracked DNOs, the Authority undertook a separate examination and assessment of SGBs. The aim of this was to identify the costs savings from SGBs which DNOs could reasonably be expected to achieve in the course of the RIIO-ED1 price control period.

(e) At the outset of this process of slow-track assessment, by reference to a number of external data sources, the majority of which had been referred to and relied upon by the DNOs themselves, and the DNOs' business plans the Authority concluded that the SGBs reflected in the business plans of all DNOs significantly understated the level of SGBs which ought reasonably to be achievable over the price control period.

(f) Over the course of the slow track assessment process, the Authority's approach to (i) the quantitative assessment of the additional SGBs that could reasonably be achieved in addition to those reflected in the DNOs' business plans, and (ii) the allocation of those additional savings among DNOs, was the subject of refinement. There was nothing unlawful, peculiar or "wrong" about that. The refinement of the Authority's approach reflected a process of engagement with the DNOs, both collectively and individually. As well as having the opportunity to comment in detail on the Authority's proposed conclusions at the Draft Determination stage, DNOs were able, through workshops and presentations by the Authority and via specific requests for information and invitations to comment, to engage with the Authority on the detail of its proposed approach.

(g) Having taken account of the comments of the DNOs, collectively and individually, the Authority ultimately exercised its judgment to quantify and allocate the additional SGBs which DNOs could reasonably be expected to benefit from by reference not to external data sources but by way of a comparative examination *by category* of the SGBs which were recognised in the various DNOs' business plans. The Authority therefore identified the total reasonably achievable SGBs on a cautious and conservative basis, by reference only to DNOs' own plans (read across to other DNOs on the basis that SGBs, developed with public funding, are solutions which all DNOs are free to adopt).

Fast track assessment process

149. On the subject of the fast track assessment process, and in response to the arguments which NPg sets out at paragraphs 6.15 – 6.18, the Authority responds as follows:

(a) First, with respect to paragraph 6.15, whilst the Authority agrees that the business plans submitted by DNOs at the fast track stage included DNOs' forecast SGBs in accordance with the Authority's Guidance, the Authority does not agree with the remainder of the paragraph. Specifically:

(i) The DNOs were asked for detailed explanations and cost benefit analyses in relation to forecast SGBs, to be quantified and supported by evidence.

(ii) This requirement can be seen from, *inter alia*, Business Plan Data Table CV103 (relating to LCT reinforcement) and Business Plan Data Table S1 (for SGB savings across all costs categories) which asked for specific forecasting of SGBs.

(iii) The qualitative rather than quantitative approach to the assessment of the SGBs at the fast track stage reflected the structure of the process, namely the heightened degree of scrutiny that was inherent in the slow track process.

(b) Second, with respect to paragraph 6.16, as can be seen from the part of the Authority's Strategy Decision quoted in that paragraph, the Authority identified SGBs as a particular area of its focus from the outset. The specific approach to the assessment of SGBs developed in response to the data contained in the DNOs' business plans and the representations the DNOs made. DNOs had the opportunity to comment on the Authority's proposed approach at the Draft Determination stage and through bilateral and multilateral engagement with DNOs.

(c) Third, with respect to paragraph 6.17:

(i) Whilst it is correct that at the fast track stage the Authority did not attempt to estimate SGBs, this did not reflect any belief that the cost benchmarking would identify SGB inefficiency without separate analysis of SGBs.

(ii) The reason why no independent process of assessment of SGBs was undertaken at the fast track stage was a product of the fast track/slow track assessment system structure and the lighter touch assessment involved in the former.

(iii) The assessment of efficient costs under the fast track assessment did not presume to account for all SGBs and the final quote in paragraph 6.17 is taken out of context. The method to which the quoted passage refers concerned the Authority's approach to a specific element of costs assessment, namely allowances for positive adjustments in respect of LCT-related reinforcements.

(d) Fourth, the Authority agrees that paragraph 6.18 is an accurate description of its application, and the outcome, of the fast track assessment process. As set out at paragraph 2.13 of the Strategy Decision - Business Plans and Proportionate Treatment [**NPg/1/B/8/ para. 2.13**], "*the agreed settlement for the fast-tracked DNO will be their view of the revenue it needs to run its network*".

150. On the subject of the assessment of NPg's business plan at the fast track assessment stage, set out at 6.19 – 6.22 the Authority responds as follows:

(a) Paragraph 6.19 is agreed. NPg failed to score a green ranking in the category of efficient costs. As to the second sentence of paragraph 6.35, the Authority does not agree that SGBs were assessed under the outputs criterion (in respect of which NPg received a green light assessment). Nor did the summary comment set out in the third sentence of paragraph 6.35 constitute the totality of the Authority's concerns at the fast track stage. Rather, as was identified in the NPg Fast Track Assessment [**NPg**/**2/B/5**], the Authority had more general concerns about the lack of quantification in NPg's business plan.

(b) As to paragraph 6.20, whilst it is agreed that NPg received a green ranking for the second criterion, outputs, as mentioned in a. above the Authority does not agree that SGBs were considered within that criterion. The Authority refers to its assessment in the NPg Fast Track Assessment [**NPg**/**2/B/5**] where smart grids are listed under the third criterion, cost efficiency.

(c) As to paragraph 6.21, the quoted part of the Authority's assessment at fast track stage of NPg's business plan with respect to cost efficiency, the criterion in respect of which NPg received an amber light, identified the concern that NPg's plan contained "*no quantification of the benefits or financial savings to customers of these [smart] innovations, or the improvement they have made to output targets…*"

(d) As to paragraphs 6.22, NPg ought reasonably to have understood that in respect of cost efficiency, for which it received an amber light, the Authority remained unsatisfied with its business plan in significant respects. The *broad narrative* of NPg's *strategy* in respect of SGBs appeared satisfactory to the Authority, as can be seen from paragraph 1.24 of NPg's Fast Track Assessment [**NPg**/**2/B/5**], but, as identified, NPg had failed properly to *quantify* SGBs.

Refinements of the Authority's approach to the assessment of SGBs under slow track process in the period up to Draft Determinations

151. With respect to the process of engagement the Authority undertook with NPg and the other DNOs following its publication of its fast track determinations, the Authority emphasises the following points:

(a) Contrary to paragraph 6.23, NPg failed to make refinements to its business plan so as to address the issue of the quantification of SGBs after the Authority's fast track decision, despite the Authority's feedback to NPg on the deficiencies in their business plan in respect of cost efficiency, including the issue of proper quantification [**NPg/2/B/5**].

(b) As to paragraph 6.24, the Authority investigated all responses to its fast track determinations that it received. NPg wrongly seeks to characterise the slow track assessment of SGBs as an *additional* assessment, ignoring that there was no quantitative assessment of SGBs in the "standard cost assessment framework":

(i) Whilst it is correct that in some cases the inclusion of SGBs in DNOs' submitted costs may have reduced the benchmark under the comparative cost assessment process, this is a comparative rather than an absolute measure.

(ii) The Authority perfectly properly proceeded to seek to quantify SGBs on an absolute and not a merely comparative basis. It was not 'wrong' to do so.

(iii) In the methodology which the Authority adopted, the Authority took steps, in order to account for the risk of double counting, to adjust for the fact that SGBs would to a certain extent be reflected as part of the comparative benchmarking exercise (see paragraphs 11.50 – 11.52 of the Final Determinations Expenditure Assessment Annex).

(iv) The Authority submits that its consideration of SGBs was consistent with the approach it indicated upfront as to the distinction between fast and slow track assessment.

152. With respect to the Authority's consideration of SGBs on the slow track process in the period up to the publication of Draft Determinations, the Authority had regard to a number of external sources and the DNOs' business plans which, drawing also upon its broader contextual knowledge as the sectoral regulator, led it to conclude that the level of SGBs incorporated by DNOs in their business plans were significantly and generally underestimated. Contrary to the suggestion at paragraph 6.24, the process of examination of SGBs was prefigured by the guidance which the Authority had given to DNOs as to the difference in approach between fast and slow track. In respect of the process of investigating and assessing SGBs under the slow-track assessment process, the Authority refers to the following which described its approach in The Slow Track Draft Determinations – Business plan expenditure assessment [**NPg/1/B/13**]:

(a) Under the heading "*Smart grids and smart meter benefits – Overview*", at paragraphs 11.1 – 11.2 the Authority stated, "*By 2016 consumers will have contributed up to £450m in Low Carbon Networks Fund (LCNF), Network Innovation Competition (NIC) and Network Innovation Allowance funding. Our assessment indicates that potential savings estimated by DNOs from the roll-out of their LCNF projects amount to around £2bn over the RIIO-ED1 period for particular scenarios for the take-up of low carbon technologies. The smart meter roll-out will deliver significant benefits directly to consumers as well as cost savings to DNOs. The DNOs' cost savings should be passed on to consumers who are investing in the roll-out. We have drawn on evidence from the DNOs' business plans, the Energy Networks Association (ENA) assessment of smart metering benefits, the Smart grids Forum smart grids modelling work, the DECC smart metering impact assessment and expected trends in efficiency gains due to innovation. This*

evidence indicates significant benefits should be achieved over this period."

(b) At paragraph 11.3, in respect of the fast-track assessment, the Authority noted "*[w]e undertook a qualitative assessment of smart grids and innovation in the DNOs' business plans*".

(c) In respect of the approach under the slow-track assessment, at paragraphs 11.9-11.10, the Authority explained, "*For the slow-track companies we have made an adjustment to totex to account for the benefits of smart metering and smart grids which DNOs have not incorporated into their business plans for RIIO-ED1. At fast-track we reviewed the DNOs' strategies for using smart grids during the price control on a qualitative basis. For slow-track we have looked in more detail at the savings the DNOs propose to deliver for consumers. While we recognise that some of the DNOs' strategies appear high quality, the test is the level of benefits included in the DNOs' requested allowances*." (emphasis added)

(d) The definition of what constituted a "smart" solution under the Authority's slow track assessment of SGBs was set out at paragraphs 11.12 – 11.14.

(e) The Authority set out its assessment of the savings from smart solutions embedded in DNOs' business plans at paragraph 11.5. The total savings across all DNOs amounted to £404.7 million.

(f) The Authority concluded that, in its judgment, the said level of SGBs, £404.7 million, constituted a material underestimation of potential SGBs across all DNOs. At paragraph 11.16 under the heading "*Identifying the total savings possible during RIIO-ED1"* the Authority stated, *"We do not consider that the £405m savings from the use of smart grids and smart meter data in the DNOs' business plans is sufficient. We do not believe that any DNO has taken account of the full potential of smart grids, including the use of smart metering data. The evidence indicates that further savings are possible across a range of cost areas. We*

discuss this further below in relation to the use of smart metering data, avoided or delayed increases in network capacity, and other smart grids benefits. Our figures below are based on potential savings across all 14 DNOs." The Authority concluded that total potential SGBs savings amounted to £943m (paragraph 11.23). The sources which underlay this analysis and informed the exercise of the Authority's judgment, most of which originated from the DNOs themselves, are as follows:

(i) On the basis of DECC's latest impact assessment, to which the DNOs contributed, and a 2013 study by the Energy Network Association, an additional £190m of savings should accrue to DNOs over the RIIO-ED1 price control period in respect of smart metering (paragraph 11.17 – 11.18).

(ii) On the basis of the Transform model developed by DNOs under the Smart Grids Forum, an average of 23 – 25 % of reinforcement costs should be avoidable at GB level by use of smart solutions, rather than the 14% forecast by DNOs, amounting to additional saving of £653m (paragraph 11.19).

(iii) In respect of costs savings from smart solutions other than in the area of reinforcement, only one DNO (ENWL) had identified such costs savings, but applying those savings across all DNOs would suggest savings of in excess of £200m, but amounting to at least £137m to account for uncertainty and adjust for the risk of double counting (paragraphs 11.20 – 11.21).

(iv) Further additional savings related to the development of understanding of smart solutions over the price control period were judged to have potential to yield further savings of at least a percentage point of total expenditure, but adopting a cautious approach no reduction to DNOs' allowances was proposed in this regard given uncertainty and the Authority's cautious approach to avoid double-counting (paragraph 11.22).

(g) In consequence of this analysis, the Authority set out its approach to the reasonable level of SGBs as they affected DNOs' allowed revenues at paragraphs 11.24 – 11.25. In particular, the Authority noted, "*We have reduced each DNO's totex by the remaining value of savings DNOs should have included in their business plans. The process of netting-off the savings already embedded ensures we do not double-count the benefits DNOs have already identified. It also gives the best performing DNOs on this measure credit for the savings they have identified*." (emphasis added).

Final decisions - refinement of the Authority's approach to the assessment of SGBs between Draft and Final Determinations

153. As set out at paragraphs 6.25 – 6.26, the Authority referred to the external sources identified in that paragraph and set out above in explaining its view that the level of reasonably achievable SGBs had been materially understated by DNOs. The Authority agrees that the DNOs criticised the use of the external evidence in response to the Authority's Draft Determinations and as a consequence, as explained below, the Authority adopted a more conservative approach to the identification of the total sum of SGBs which ought reasonably to be recognised and their allocation between the DNOs.

154. However, the Authority continued to have confidence in the data sources to which it referred at the Draft Determination stage (which, as noted, largely originated with or had been relied upon by the DNOs). It remained the Authority's expert judgment that the SGBs which could reasonably be expected from DNOs significantly exceeded the forecast savings set out in each DNO's business plan.

155. Contrary to the argument set out at paragraph 6.41, ensuring that the proper extent of SGBs was recognised, i.e. that DNOs were not allowed to recover charges for costs which they could reasonably be expected to avoid on account of the adoption of smart solutions over the price control period, was consistent with the approach indicated to DNOs at the outset and was in line with the Authority's regulatory obligations to consumers:

(a) Proportionate assessment did not mean, and could not reasonably have been understood to mean, that the slow track assessment would not be a detailed and rigorous examination of the DNOs' business plans.

(b) The Authority's proportionate approach meant that greater scrutiny was given in the detailed slow track assessment to those areas of DNO's business plans which were less satisfactory. In NPg's case, that meant that the Authority gave specific and detailed consideration to NPg's proposed expenditure to ensure efficient cost.

(c) The Authority rejects as misplaced NPg's attempt to cherry-pick certain comments from high level summary documents and suggest that these somehow operated to preclude the Authority from examining particular areas of costs or otherwise to limit the scope of the Authority's assessment of reasonable costs in the discharge of its regulatory price control function. Contrary to the suggestion at paragraph 6.45, the Authority was required to seek carefully to assess SGBs in the course of its slow track assessment process in order to discharge its regulatory price control function in an appropriate way so as to protect the consumer interest.

156. The Authority does not agree with NPg's argument at paragraphs 6.46 -6.47 that its own conclusions suggested inefficiency was confined to certain DNOs. To the contrary, the Authority's analysis showed that no single DNO's business plan accounted for the full range of SGBs which could reasonably be expected across the different categories in which the DNOs taken as a whole had projected saving on account of SGBs:

(a) Thus, in answer to paragraphs 6.47 to 6.50, benchmarking of DNOs for SGBs would not be effective to identify the proper extent of SGB savings across the different *categories* in which different DNOs had forecast SGBs, as each DNO was inefficient in at least one such category.

(b) The Authority's approach to the identification of SGBs at the slow-track stage was therefore not concerned with relative efficiency but with ensuring consistent take-up and application of the SGBs available to all DNOs. To the extent that a form of "benchmarking" was applied in respect of SGBs, this was simply to identify the appropriate reduction to each DNO's allowances, not to identify inefficiency.

157. However, in response to the specific comments received from DNOs the Authority determined to proceed cautiously by adopting an approach to the *quantification and allocation* of SGBs based on the data contained in all DNOs' (collective) business plans rather than by reference to external data sources. Thus, whilst at Draft Determination stage both comparative data from DNOs' own plans and external data were relied upon to quantify and allocate SGBs, at Final Determination stage both the identification and allocation of SGBs were confined to DNOs' own plans/data.

158. The Authority does not agree with the suggestion at paragraphs 6.26, 6.37, 6.40, 6.42 and 6.43 that there was any marked change of approach, still less that this was a "*wholly new approach*", to SGBs. Whilst it is correct that the Authority's judgment throughout the slow track process remained, as a result of its detailed assessment, that additional SGBs beyond those identified in DNOs' business plans ought to be recognised, that was a constant conclusion throughout the slow track assessment process and not the product of any new approach. The Authority's process was, perfectly properly, refined in response to the representations made by DNOs and the process, and rationale for it, was explained at Section 11 of the Final Determination – Business Plan Expenditure Assessment [**NPg/1/B/16**], as follows:

(a) Under the heading "*Decision and results*", at paragraph 11.2, "*We have retained the approach of applying an adjustment to embed smart grids and other innovation savings in DNOs' allowances. We have reviewed the responses and have made a number of changes to our methodology for final determinations. The final determinations adjustment for smart grids and other innovation for each DNO is in table 11.1*."

(b) The focus on DNOs' own business plan was set out at paragraphs 11.4 and 11.8 which explained that reinforcement and other cost area SGBs were assessed by benchmarking and other methods of identifying best performing DNOs by cost area.

(c) At paragraphs 11.15 – 11.20 the Authority explained the sources upon which it relied and its approach to the quantification of SGBs and consequential adjustments to DNOs' allowances.

(d) At paragraph 11.21, the Authority summarised the range of responses that had been received to its approach at Draft Determination stage as follows, "*Most DNOs disagreed that there is evidence that more savings from smart grids and smart metering can be achieved than those already in their business plans. Some DNOs accepted the principle of our adjustment and that more savings could be included in their allowances. They disagreed on the size of the adjustment. A number of DNOs thought smart grid savings should be delivered to consumers via the efficiency incentive during the period with no ex ante adjustment. One DNO proposes a mid-period review of smart grid savings to set an adjustment for the remainder of the RIIO-ED1 period. An energy supplier supported our proposed adjustment and suggested applying a further reduction to DNOs' allowances. A consumer organisation perceived that the DNOs are reluctantly embracing the opportunities of smart grids and smart metering. It supported the proposed adjustment*…"

(e) The DNOs made further specific comments as to the Authority's proposed methodology, which the Authority summarised at paragraphs 11.23 – 11.35.

(f) In response, the Authority explained that its judgment remained that a number of DNOs had failed to embed sufficient savings from smart grids, innovation and smart metering in their business plans and that DNOs' allowances should be adjusted accordingly, but that:

(i) It was reflecting a number of the points raised by DNOs so as to recognise various additional embedded savings as smart savings (see paragraphs 11.36 – 11.48). The Authority appropriately considered the DNOs' representations on the full extent of SGBs which the DNOs contended ought to be recognised in their revised business plans. The Authority does not agree with the contention at paragraph 6.36 that it did not pay due regard to revisions to NPg's business plan and the further justifications it put forward. To the contrary, at the Final Determination stage the Authority both considered the additional information put forward by NPg with the effect that it recognised significantly more embedded benefits and also carefully considered the explanations put forward by NPg in support of its approach. The Authority described its approach at paragraph 11.55, "*We assessed additional information provided by DNOs to determine the smart grid benefits embedded in their business plans. We recognise that there was an incentive on DNOs to overstate the value of savings in their plans to avoid additional adjustment. To mitigate this, we have only accepted benefits that are justifiably smart and that were referenced in the DNOs' business plans*."; and

(ii) It was identifying the level of additional SGBs and allocating them among DNOs by reference only to the DNOs' own data from their business plans, examining the different categories (areas of spend) to identify the best performing DNO in each category and applying (appropriately calibrated and adjusted) savings to all DNOs. Thus, at paragraph 11.49, the Authority stated "*We accept that the allocation of savings in draft determinations did not fairly reflect the ability for DNOs to achieve them. In final determinations we allocate savings according to expenditure in each area. This better accounts for the ability of DNOs to achieve savings. For example, a DNO with a large reinforcement allowance is required to deliver higher*

absolute reinforcement savings than a DNO with a small reinforcement allowance."

(g) Thus, contrary to the implication at paragraph 6.39 that the Authority acted unfairly in adopting the approach it did at Final Determination stage, what NPg suggests was an approach which "*had not been presaged…at the Draft Determination stage*" was in fact the perfectly proper refinement of the approach at Draft Determination stage so as to respond to the feedback received from DNOs.

(h) The Authority rejected the suggestion that its approach involved double counting or that is conclusions on appropriate adjustments to account for SGBs went beyond what could be reasonably expected, explaining at paragraphs 11.50 – 11.52: "*There is no double counting of smart grid and other innovation savings with ongoing efficiency. All DNOs have forecast smart savings in addition to ongoing efficiency and we are not including savings from smart grids that also form part of the ongoing efficiency assumption. Given the level of investment consumers have made in innovation projects and the smart metering programme, we would expect savings from these in additions to historical levels of ongoing efficiency. We have no evidence that ongoing efficiency forecasts for RIIO-ED1 are significantly above those for previous price controls where these factors did not apply. We have undertaken a top-down assessment of the additional savings we are requiring DNOs to deliver. This demonstrates that the adjustment for smart grids and other innovation represents on average an additional implied frontier shift of 0.2% per year for slow-track DNOs. This compares to ongoing efficiency assumptions embedded in DNOs' business plans of between 0.8 and 1.1% per year. We consider that this additional evidence demonstrates our adjustment is appropriate and corroborates our benchmarking assessment. We have not seen evidence of there being material double counting between the smart grids and other innovation assessment and the general cost assessment….We have excluded the*

LV fault finding cost area from our assessment because of the risk of double counting in this category."

(i) As to paragraphs 6.51 to 6.53, the Authority was correct to conclude that the emergence of SGBs should result in greater levels of ongoing efficiency savings. The savings relating to SGBs represent a return on the investment into innovative technology from public funds such as the LCNF and smart metering programme. The purpose of this investment was to identify efficiencies driven by technological change, over and above conventional ongoing efficiency savings. The DNOs' own Transform model shows that smart solutions produce additional, net cost savings in resolving load related issues through smart rather than conventional techniques. The identified savings are additional to ongoing conventional savings linked to productivity growth. The Authority does not agree with the description of a "back-up methodology". Rather than a methodology, this was a *factor* which the Authority properly took into account in informing its judgment of the appropriate balance of risk between DNOs and consumers in the modelling of SGBs over the price control period.

(j) The Authority explained why, at Final Determination stage, it was adopting an approach which focused on the realistically *achievable* SGBs for all DNOs by category rather than as at fast stage confining the assessment of each DNO to those smart solutions which each DNO, respectively, already planned to deploy. At paragraph 11.53 the Authority stated, "*We consider it would be inappropriate to base the smart grid assessment on the level of innovation funding each DNO has received. The DNOs should be considering innovations developed by any DNO. DNOs should be working hard to ensure the learning from their own projects is shared across the industry as all consumers pay for it. We consider an ex ante adjustment for smart grid and other innovation savings to be appropriate. An uncertainty mechanism would reduce incentives on DNOs to reduce costs and implement smart grid*

and other innovative solutions in the early part of the price control period."

(k) The Authority recognised that there were additional potential SGBs beyond those which were captured by its assessment (see for example paragraphs 11.47 and 11.56) but considered that its approach was the appropriate way to proceed in balancing the consumer interest in identifying the full range of achievable savings related to SGBs without placing an undue burden of uncertainty arising from the modelling process on DNOs over the price control period. Contrary to paragraph 6.44, the Authority did not "drop" its reliance on the reliable sources of data identified at Draft Determination stage. Rather, as explained above, those data sources continued to support the Authority's judgment that additional SGBs reducing the DNOs costs could reasonably be expected over the price control period, however at Final Determination stage the Authority did not rely on those external data sources in order to *quantify and allocate* the SGBs to be recognised but confined itself to data from the DNOs' own business plans.

159. The result of the Authority's examination of the additional information and representations provided by DNOs between Draft and Final Determination stages on the slow track process was that the Authority's assessment of total embedded SGBs and further adjustments to allowable costs to reflect reasonably achievable SGBs evolved from:

(a) £405 million recognised embedded SGBs and a proposed additional adjustment of £396 million across all DNOs at *Draft Determination stage*; to

(b) £641 million recognised embedded SGBs and a proposed additional adjustment of £322 million at *Final Determination stage*.

160. With respect to the impact of the Authority's calculations at Draft and Final Determination stages, and by way of answer to paragraph 6.32:

(a) As set out at paragraph 6.32, the further adjustment to NPg's allowable costs as a result of the slow track assessment of SGBs was £42 million, in addition to the £91 million of SGBs which the Authority recognised as already being embedded in NPg's revised business plan. The adjustments are as set out at paragraph 6.33 and the table referred to therein.

(b) This represented a significant reduction to the proposed adjustment to NPg's allowable costs as set out at Draft Determination stage, which was a proposed pre-interpolation adjustment of £81 million of SGBs in addition to £36 million of SGBs which the Authority recognised as embedded.

(c) Had embedded benefits been assessed at Draft Determination stage at the level they were assessed at during the Final Determination stage, the Draft Determination approach would have been more exacting on NPg than the approach adopted at Final Determination.

161. In assessing SGBs on the basis of what could reasonably be expected of DNOs over the price control period, the Authority considered the different categories in which such smart solution savings could be obtained. No single DNO was the best performing DNO across *all* cost categories, and thus to that extent paragraph 6.37 is correct to identify that all the DNOs' business plans could be characterised as being below optimal efficiency. The Authority's approach at Final Determination stage informed the identification of the total amount of SGBs which should be recognised across all DNOs and the appropriate allocation of those SGBs among DNOs. Further:

(a) The exercise was not, contrary to the statement at paragraph 6.39, a "partial benchmarking" exercise. The Authority scrutinised by category the smart solutions which had been included by the various DNOs. This exercise involved examination of the different business plans, not to obtain a benchmark but to identify the total potential savings across all categories.

(b) The Authority considered the DNOs' business plans to identify the DNO with the greatest SGB cost saving in each category. This analysis was intrinsically linked to the DNOs' own projected costs savings, rather than attempting to quantify total potential SGBs by reference to external sources. The total figure produced by this approach was therefore more cautious than an approach which sought to identify potential SGBs by reference to a broader range of data sources than DNOs' own plans. Furthermore, in its approach the Authority proceeded by reference only to 4 categories:

(i) General reinforcement (LV-EHV)

(ii) General reinforcement (132kV)

(iii) Fault level reinforcements; and

(iv) Other.

(c) To take a simple example, if the leading DNO in each of the four categories identified SGBs of £10 million, the total achievable SGBs across all DNOs would be the sum of £40 million multiplied by the number of DNOs but scaled for each DNO according to its relative level of expenditure in those categories.

(d) The Authority's approach was, however, made more cautious in that:

(i) First, it did not apply a market leader/frontier DNO approach to determining the achievable savings in each category but rather applied an upper quartile/75% approach for the three reinforcement categories as explained at paragraph 163(a)(i) below. Thus, on the example above the £40 million saving would be scaled back on the application of the upper quartile/75% approach.

(ii) Second, the Authority only adopted 4 categories although the fourth category, "Other" was in fact comprised of 6 subcategories (asset replacement/refurbishment; trouble call; inspection and

maintenance; tree cutting; ONIs and Operational IT and telecoms). Instead of seeking to identify the market leading DNO's SGBs in each of these sub-categories, the Authority identified the market leading DNO across all of those sub-categories taken together as the "Other" category. This had the effect of *lowering* the total savings to be achieved on account of the SGBs in this category by £137m (pre-interpolation) across all DNOs (including WPD), and by £17m for NPg, as no one DNO was the market leader across all sub-categories.

(e) Having identified the market leader by category of smart saving, the Authority then applied the resulting saving to each DNO proportionately, taking account of those SGBs which were already recognised to provide the total reasonable SGB allowances which should be recognised for each DNO.

162. The Authority does not agree with the argument at paragraph 6.54 to 6.55 that by comparison to the lighter touch approach at the fast track assessment stage or the approval of WPD's allowances at the fast track stage, the treatment of NPg and the other slow tracked DNOs was in any way discriminatory. The proportionately lower SGB allowances applied to WPD are a direct product of its satisfaction of the fast track criteria. WPD was the only DNO which was fast tracked as the most efficient DNO in the round at the stage of fast track assessment but all DNOs had an equal and fair opportunity to qualify for the fast track. Whilst fast tracked DNOs were assured that they would not end up with materially less favourable settlements than slow tracked DNOs, for obvious reasons of incentive and fairness slow-tracked DNOs could never reasonably have assumed that the outcome of the slow track assessment process would be no different than to apply to them the same outcome as applied to fast-tracked DNOs. Furthermore, certain aspects of WPD's business plan which were initially not treated as smart were subsequently, following representations by slow tracked DNOs, deemed to be smart by the Authority. Thus the assessment of WPD's embedded SGBs would in any event have been higher than is apparent from their business plan

at fast track stage. The slow-tracked DNOs requested that the Authority exercise caution in considering additional SGBs put forward by WPD after it had been fast-tracked, on the basis that any such additional SGBs recognised would not affect WPD's allowable revenues (given the conclusion of the assessment process for WPD under the fast track) but would affect the slow-tracked DNOs, thus potentially incentivising WPD to overstate the level of additional SGBs it could find. Thus, whilst WPD was included in the process of identification of total SGBs on the slow track, the Authority adopted a cautious approach to the recognition of additional SGBs from WPD and ensured that the additional benefits recognised did not negatively impact the other DNOs.

Methodological complaints

163. The Authority does not agree that the complaints as to its methodology summarised at paragraph 2.8 and set out at paragraphs 6.58 – 6.72 are well founded. Specifically, the Authority responds as follows:

(a) As to paragraphs 6.59 – 6.62, the Authority does not agree that its approach involved double counting:

(i) The Authority accepts that cost benchmarking analysis is likely implicitly to reflect some differences in submitted SGBs. The Authority recognised that its identification through slow track assessment of SGBs which could reasonably be expected to arise during the price control period additional to the SGBs already embedded in DNOs' business plans presented a *risk* of double counting. Contrary to the suggestion at paragraph 4.13 of Annex 4 to the Frontier Report, the Authority recognised that there might be material double counting and therefore took steps to remove any double count. Those steps were:

(1) Setting the required level of SGBs at the upper quartile rather than the frontier mark in two of the reinforcement categories: general reinforcement (LV-EHV) and general reinforcement (132 kV). This reduced the adjustment for these two categories by £108 million.

(2) Setting the required level of SGBs at 75% of the best performer in the third reinforcement category, fault level reinforcement (where there were not enough data points to calculate an upper quartile). This reduced the adjustment for this category by £16 million.

(3) Removing a significant cost category (LV fault finding, which forms part of the trouble call sub-category) from the "Other" category on account of the same DNO setting the benchmark in that category in the cost assessment. The Authority notes that the DNOs setting benchmarks did not necessarily have *any* SGBs in their plan for the relevant category. For example, outside the category of General reinforcement - LV-EHV, many DNOs did not have any SGBs in the other three categories. This reduced the adjustment for this category by £150 million.

(ii) As a result of the steps set out above, the Authority considered, and submits, that the residual risk of double counting is either non-existent or immaterial as all cost areas identified as presenting a material risk of double counting have been appropriately adjusted. The steps set out above reduced the total adjustment for the industry by £274 million (as the DNOs would well have understood by straightforward calculations using the models which they were given, and by reference to the method explained at paragraphs 11.4, 11.46 and 11.52 of the Final Determinations – Expenditure Assessment Annex). Thus, even if NPg is correct (see paragraph 4.28 of Annex 4 to the Frontier Report) that the Authority's cost assessment process removed £43 – 82 million from the sector by embedding this amount of additional SGBs in Ofgem's view of efficient allowances prior to the SGB assessment, the steps taken by the Authority more than compensated for any potential double count.

(iii) The Authority does not agree with NPg's analogy between the approach to RPEs and SGBs. This is not an appropriate analogy as RPEs have always been forecast separately and are not embedded in costs. A better analogy is between SGBs and ongoing efficiency assumptions. As with SGBs, the latter form a part of the submitted costs used for cost assessment modelling. If the Authority had found the DNOs to be inefficient in their ongoing efficiency assumptions then the Authority would have made a subsequent adjustment after cost assessment modelling.

(b) As to paragraphs 6.63 – 6.67, the Authority does not agree that its approach was in any way vitiated with regard to the issue of prevailing levels of efficiency. Specifically:

(i) The analysis in assessing SGBs which the Authority undertook on the slow track involved the identification of total SGBs which could reasonably be expected to arise during the price control period. That analysis was not affected by the prevailing level of efficiency of any one DNO.

(ii) The adjustment that the Authority made to reflect the SGBs that ought reasonably to be reflected in the DNOs' allowances was not a measure designed to ensure "catch up" efficiency, which is dealt with by the comparative cost assessment exercise. The adjustment for SGBs was designed to shift the efficiency frontier.

(iii) Whilst prevailing levels of efficiency are relevant to the second, they are not relevant to the first.

(iv) Furthermore, the Authority disagrees with the assertion at paragraph 6.65 that the benchmarks in the SGB models are set by DNOs who trail the efficient frontier in the cost models. Considering NPg's analysis, it is noted that:

(1) For EHV-LV reinforcement, three of the four DNOs at or above the benchmark in SGB assessment are at or above the benchmark in the relevant comparative cost assessment.

(2) For 132kV reinforcement, two of the four DNOs at or above the benchmark in SGB assessment are above the benchmark in the relevant comparative cost assessment.

(3) For fault level reinforcement, the DNO setting the benchmark in SGB assessment was the best performer in the relevant comparative cost assessment.

(4) For the other category, where the methodological difficulties with comparing against the cost assessment are greatest, the DNO setting the benchmark in SGB assessment (ENWL) is identified as marginally below the benchmark in the relevant comparative cost assessment.

(v) Therefore, on NPg's own terms, the Authority can see that of the 10 DNOs at or above the benchmarks in SGB assessment, the majority (six) are among the good performers in the relevant comparative cost assessment. This is directly contrary to NPg's claim.

(vi) We note that NPg is one of the worst performing DNO groups in cost assessment (see the efficiency scores at Table 2.4, page 13 in the Final Determinations Expenditure Assessment Annex [**NPg/1/B/16**]). On the logic of NPg's argument, with which the Authority does not agree, NPg ought therefore to have more scope to find savings than its more efficient counterparts.

(vii) The SGB adjustment applied by the Authority was scaled in proportion to the size of the allowance produced by the cost assessment. Thus, for a DNO deemed more efficient under the cost assessment exercise, and thereby receiving a greater

allowance/being subjected to a lesser reduction, their recognised embedded SGBs would also be higher. By contrast more extensive reductions to a DNO's costs under the cost assessment exercise would also have the effect of applying a higher reduction to the level of embedded benefits recognised.

(c) As to paragraphs 6.68 – 6.72, the Authority does not agree that its approach rewarded savings from smart over conventional solutions. The Authority's approach was concerned with incentivising DNOs properly to consider the smart solutions available to them as a result of the funding which consumers have put into the development of smart solutions and smart metering. The ongoing efficiency assumptions of the DNOs were broadly similar. The measure of SGBs available across the different categories is a measure of the additional savings which DNOs can reasonably be expected to find beyond the conventional solutions they all broadly assumed. As the Authority's Strategy Decision – Outputs, incentives and innovation explained at paragraph 10.4, "*We will take account of past and future innovation funding provided to DNOs in setting the efficiency frontier for the period (ie we would expect the high levels of innovation funding to date to allow DNOs to achieve results more efficiently)".* Further:

(i) The Authority notes that the exercise with which it is concerned is the determination of allowable revenues during the price control period. Over that period, it is open to DNOs as a matter of fact to deploy whatever solutions (smart or conventional) it considers are best placed to help it reduce its costs. The efficiency incentive will incentivise DNOs to deploy the most efficient solutions as the price control period unfolds.

(ii) As to the final sentence of paragraph 6.70, the quoted comment relates to one specific aspect of the fast track assessment process, allowances to positive adjustments in respect of LCT related reinforcement. The fast track assessment process in general sought to assess costs in the round, without detailed

examination and quantification of different categories of likely savings.

(iii) The Authority's approach to smart benefits had the effect of incentivising DNOs to implement the cost savings arising from publicly funded trials of smart solutions, including the use of smart metering data. Alternatively, if DNOs determine not to deploy those technologies, and thus fail to achieve the consequential cost savings, the Authority's approach properly places the cost burden of not achieving those savings on DNOs rather than enabling them to pass on that cost burden to consumers on the basis of less effective business-as-usual technology and solutions. This approach is entirely consistent with the Authority's regulatory responsibilities.

Alleged material errors in implementation of the Authority's approach

164. With respect to the claim made at paragraph 2.9 (and detailed at paragraphs 6.74 to 6.106) that the Authority made material errors in its approach the Authority submits that in general these were not errors, for the reasons set out below. In the one instance where the Authority accepts it did make an error the impact was not material in the context of the overall value of the price control.

165. As to the mathematical error in calculating percentages referred to at paragraphs 6.74 to 6.80:

(a) The Authority accepts that a mathematical error was made at one part of the process to calculate the percentage of smart savings to be applied to NPg, in that the Authority used as its denominator for the equation described in paragraphs 6.75 and 6.76 submitted costs rather than submitted costs excluding SGBs. The Authority agrees with paragraphs 6.75 to 6.78.

(b) However, the Authority does not consider that this error was material. As to paragraph 6.79, whilst the Authority accepts that there is a miscalculation it does not consider that the effect of that error was any

significant overestimation of the SGBs that DNOs can reasonably be expected to achieve. As explained below the Authority considers that a proper correction of the error would involve an adjustment of £3.8 million rather than the £5.8 million posited by Frontier. The basis for the Authority's calculations is set out below. However, on either view of the quantum of the correction the Authority submits that the error is not material and there ought therefore to be no adjustment to the Authority's Final Determination as:

(i) The Authority removed £274 million of potential SGBs from its assessment in order to mitigate against the risk of double counting. Given that NPg have quantified double counted benefits in the (unadjusted) figures to fall within the range of £43 – 82 million, this means that even at the highest end of NPg's calculations an additional £192 million has been removed.

(ii) Additionally, as set out above, the Authority's conservative approach to the assessment of SGBs in the sub-categories making up the Other category, i.e. treating the category as a whole rather than by sub-category, meant that the quantum of SGBs anticipated for all DNOs was reduced by £137 million, of which £17 million related to NPg.

(iii) In its approach to both of these elements, the Authority could reasonably have adopted a more stringent view of the level of SGBs to be recognised. The Authority considers that taken together these two elements of the Authority's approach make appropriate allowance for minor errors such as the £3.8 million error that NPg has identified.

(iv) The Authority notes that the post-interpolation error of £3.8 million represents only 0.1% of NPg's final interpolated allowance. Interpolation is used in recognition of the fact that the Authority does not have perfect information and can only conduct its assessment with a reasonable degree of precision. It

is in the nature of a price control settlement that it does not produce a single "correct" figure, but a figure which is representative to a reasonable level of accuracy. An error at the level of 0.1% of accuracy is comfortably within an allowable margin of error where adjustments in pursuit of accuracy are spurious. By way of supporting evidence of the threshold for materiality in this price control process, the Authority notes that the uncertainty mechanisms built into the price control have a materiality threshold of 1% of a DNO's overall allowance before they are triggered.

(c) If (contrary to the Authority's primary case) the CMA considers that an adjustment ought to be made to the Final Determination, the Authority does not agree with the suggested quantification of the effect of the error advanced on behalf of NPg (in the Frontier Report) of £5.8 million. The Authority considers the appropriate figure before interpolation would be £5.1 million, which equates to £3.825 million after interpolation. Specifically:

(i) The proposed solution to the mathematical error suggested by Frontier corrects for the initial error in the benchmark ratio, but also creates additional errors. These errors are as follows:

(1) Frontier incorrectly calculates the level of embedded benefits in respect of one smart solution, Condition Based Risk Management, for three DNOs: NPg, WPD and UKPN. Frontier's calculation does not correctly cap these benefits at the same proportion as set out in the business plan of ENWL. This therefore does not ensure that NPg is on parity with ENWL as required. Frontier calculates the benefits from Condition Based Risk Management with reference to the 'conventional' submitted cost in the relevant cost category (Asset Replacement and Refurbishment) including the benefits from Condition Based Risk Management calculated on a different basis.

The proportion is incorrect in the Final Determinations as it is not based on the saving compared to the 'conventional' cost, however Frontier's analysis fails to correct for this error.

(2) Frontier incorrectly calculates the embedded benefits in efficient cost allowances. Frontier simply assumes the same SGBs are embedded in submitted and efficient allowances. This is illogical given the change in allowance, and was not supported by the DNOs following the Draft Determinations: for example SPEN stated in its response to Draft Determinations in paragraph 10.26, "*We believe that this is logically inconsistent and that any allocation of benefits should be made on the basis of the final cost allowance rather than the proposed allowance"* **[RDB/ tab 17]**.

(3) Efficient allowances are calculated as a proportion of submitted allowances. The benchmarking exercise calculates the proportion of the efficient cost that each DNO's submitted allowance represents. For example, if the DNOs are benchmarked on unit cost, the adjustment to each DNO's allowance is calculated by taking the ratio between the benchmark unit cost and the submitted unit cost for each DNO. This ratio gives the proportion by which the submitted allowance needs to be adjusted to bring it in line with the efficient level. So, if a DNO has unit costs double that of the benchmark, the ratio between the benchmark and the DNO (1:2) gives the figure by which the DNO's submitted cost needs to be adjusted (i.e. 50%). Therefore it is only appropriate to assume the SGBs also scale proportionately so that efficient allowances have the same *proportion* of SGBs as submitted allowances.

(4) Frontier had made the following errors:

a. In the calculation of total potential SGBs in each cost category. This calculation uses the 'conventional' efficient cost, which in Frontier's method includes an incorrect amount of SGBs as it wrongly assumes the same absolute SGBs are embedded in efficient cost as in submitted cost.

b. In the calculation of the apportionment of the total potential SGBs in the 'Other' category between DNOs and cost categories. This calculation uses the 'conventional' efficient cost, which as stated above in Frontier's method includes an incorrect amount of SGBs as it wrongly assumes the same SGBs are embedded in efficient cost as in submitted cost.

(ii) The Authority considers that the appropriate solution to these errors is as follows:

(1) The calculation of the benefits to NPg, WPD and UKPN from Condition Based Risk Management should be based on the proportion of savings ENWL achieves compared to its conventional submitted allowance, i.e. the submitted cost with SGB savings added back to that total to produce the total amount of the allowance absent SGBs. This proportion can be calculated using the known figures of the DNOs' submitted allowance (i.e. the allowance each DNO forecast), each DNO's submitted SGBs, and the SGBs relating to Condition Based Risk Management. This ratio can then be used to calculate the cap for NPg, WPD and UKPN. The way in which that calculation is performed is explained in the witness statement of James Goldsack.

(2) The SGBs embedded in efficient allowances can be calculated by assuming that the same proportion of savings is present in submitted and efficient allowances. By using straightforward algebra it is possible to calculate the value of SGBs embedded in efficient allowances. The Authority considers this is the appropriate way of calculating the actual amount of embedded SGBs in efficient allowances and facilitates a more accurate calculation of potential SGBs in each cost category and apportionment of total SGBs in the 'Other' subcategories between DNOs and cost categories. This is explained further in the witness statement of James Goldsack.

(iii) Furthermore, as a result of interpolation any of these cost adjustments would in any event be reduced by 25% in the process of calculating the final allowance.

166. As to paragraphs 6.81 to 6.88, the Authority disagrees that it made a mathematical consistency error in the identification of the efficient smart savings embedded in the plans of the Appellants (and other DNOs) for the "Other" category:

(a) First, there is a range of potential methods for determining the share of SGBs to be apportioned between each DNO and cost category. The Authority submits that there is no one "correct" method, but a number of different possible approaches that were reasonably open to the Authority. The Authority submits that the approach it took was one such approach and that NPg has identified no error of principle in the Authority's judgment to adopt that approach.

(b) Second, the Authority took the decision to calculate potential SGBs in the "Other" cost category by treating it as a single category. This meant that the Authority looked to identify the total savings of the leading DNO by reference to the total across all of the "Other" subcategories rather than calculating the total SGBs by reference to the

leading projected savings in each sub-category. This had the effect of *reducing* the total SGBs expected in respect of the Other category, since no one DNO was the market leader in each sub-category, and therefore *reduced* the overall reduction of DNOs' revenues on account of SGBs.

(c) Third, having identified the total SGBs in the Other category in this rather conservative way and having scaled the savings to reflect total savings across all DNOs, the Authority then apportioned by DNO the SGBs that could reasonably be expected to arise in the Other category in accordance with the proportion of that DNO's expenditure in each sub-category. The Authority took this approach because in its judgment expenditure was a good proxy for a DNO's opportunity to achieve savings in a particular sub-category. The Authority notes that this approach commanded support from DNOs at Draft Determination stage. In particular, NPg argued that this approach should have been adopted at Draft Determinations in respect of the allocation of SGBs to reinforcement expenditure [**NPg/4/B/26]**.

(d) Fourth, in order to apply the appropriate adjustment per sub-category, by DNO, the Authority needed to calculate the embedded SGBs in each sub-category. The Authority already had this information from each DNO and therefore used that data, scaled according to the outcome of the cost assessment, in order to identify the appropriate adjustment to be applied. The Authority agrees with the description of its process set out at paragraphs 6.83 to 6.86, save that:

(i) It does not agree that the further information that it gathered on the slow track was gathered "late". Evidence of smart savings had been requested of DNOs from the outset of the process.

(ii) The description at paragraph 6.86 omits the last part of the process, namely the allocation of savings to individual cost categories.

(e) The Authority submits that it therefore adopted a logical and reasonable approach that properly reflected DNOs' opportunity to achieve savings by category. The approach also reflected DNOs' concerns that absent a sub-category by sub-category assessment they would be penalised for any imprecision in the allocation of benefits.

(f) For these reasons, the Authority does not agree that the process it undertook involved any error or inconsistency and does not agree with paragraph 6.87.

(i) Had the Authority adopted the approach of considering the total achievable SGBs by reference to each sub-category rather than by reference to the Other category as a whole, NPg and the other DNOs would all have been subject to *larger* cuts in their allowable revenues.

(ii) The fact that a third potential approach could have led to a smaller reduction to NPg's allowable revenues does not show, or indicate, that the Authority was wrong to adopt the approach it took, and it is submitted that the Authority was not wrong.

167. As to paragraphs 6.89 to 6.95, the Authority does not agree that it made data handling errors in relation to spending on fault-level reinforcement. The Authority addresses the three alleged errors in turn:

(a) First, the Authority does not accept that the approach it adopted to the adjustment of costs properly to reflect SGBs was in any way erroneous in the absence of what NPg describes as a "reality-checking" exercise to ensure that "results would arise in practice", i.e. that each DNO could achieve each modelled saving:

(i) The Authority was engaged in a process of modelling over the price control period, including the smart savings that could reasonably be expected to arise. It was reasonably open to the Authority to undertake that process in a number of ways.

(ii) In undertaking that modelling process, there was no obligation on the Authority to proceed by reference to individual categories within which SGB savings might arise, and NPg identifies no error in pointing out that the Authority determined in its judgment to proceed in a different way. It would have been open to the Authority to make an adjustment to the general efficiency frontier for all DNOs to reflect the level of SGBs reasonably likely to arise. Instead, in consequence of representations made by the DNOs, the Authority adopted the approach of examining individual cost categories to quantify and allocate savings more precisely.

(iii) In circumstances where (a) smart solutions were in almost all cases developed with public funds and (b) the results of relevant research trials and the solutions that arise from it are open for adoption by all DNOs, and (c) DNOs had been asked from the outset to consider all solutions available to them, it is submitted that absent evidence from a particular DNO that it had considered and properly rejected the possibility of achieving smart savings in a particular category, it was reasonable of the Authority to read across to that DNO (appropriately scaled) the savings identified by another DNO in the same cost category. NPg provided no such evidence to the Authority in relation to fault-level reinforcement.

(iv) In reviewing NPg's fault level reinforcement scheme documentation, the Authority judged that NPg had not considered all relevant emerging trends in the use of fault current limiters and or any other smart solutions (for example, commercial arrangements with customers to change output in the event of a fault, or additional monitoring of fault currents) in this area.

(v) The Authority does not agree that the modelled savings in respect of fault level reinforcement were not available to NPg.

However, and in any event, the Authority submits that the appropriate approach on appeal is for the CMA to consider whether the Authority was entitled to rely on the analysis and evidence it did to reach its judgment in relation to the SGBs that were likely to arise in respect of fault level reinforcement.

(vi) Accordingly, the Authority submits that NPg have not identified any basis for concluding that the Authority's approach was wrong.

(b) As to paragraph 6.91, the Authority agrees that it identified savings to be made by NPg from the plans of SSE but does not agree that these were not relevant to NPg:

(i) SSE's solutions are suited to 11kV and 33kV networks, which account for all of NPgY's, and half of NPgN's, efficient expenditure in this category. SSE evidenced a smart solution for these type of networks and the savings from SGBs in this field were embedded in its business plan.

(ii) Whilst it is accepted that NPg has been involved in two trials in respect of 11kV and 33kV fault current limiters which NPg considers have not proved successful (being economically unsuccessful in the case of the 11kV trial and technically unsuccessful in the case of the 33 kV trial) and which form a part of the data from which SSE has drawn, SSE identified, evidenced and accounted for SGB savings in this area. The Authority refers to internal page 67 (pagination page 909) of SSE's Business Plan Technical Appendix 12, in which SSE explained how it had drawn from pre-existing trials, "*…our fault limiter core innovation (p. 107) is drawing on outcomes from other DNO-led projects such as the Northern Powergrid-led '33kV Superconducting Fault Current Limiter' project.*" The SSE plan for the deployment of 33kV fault current limiter technology includes a non-superconducting technology, whereas NPg

trialled a superconducting technology at 33 kV. The Authority does not agree with NPg's supposition (at paragraph 30 of the witness statement of Mark Drye) that SSE have misunderstood existing trials.

(iii) In respect of 33 kV solutions, the Authority notes that there are also additional potential solutions already in existence and that may become viable as a business as usual solution during the RIIO-ED1 price control: for instance ENWL has trial fault level current management solutions on 33 kV through its LCNF Tier 1 project Fault Current Active Management.

(iv) In respect of the other half of NPg's efficient expenditure, which related to 66kV, it is correct that there is not presently fault current limiter technology that is routinely used at 66 kV. However, the Authority makes the following observations in this regard:

(1) First, there are other potential applicable smart solutions:

a. For example, WPD's FlexDGrid LCNF project, which focuses on 11 kV networks, includes elements such as its method alpha enhanced fault level assessment and method beta real-time network management which can be applied to 66 kV networks.

b. Further, ENWL's FLARE project commencing this year aims to demonstrate that fault current can be managed at lower cost using existing assets and new commercial techniques, by use of intelligent software.

(2) Second, NPg's business plan and the documentation it provided to the Authority did not demonstrate that it had considered smart solutions in respect of its 66 kV network at Blyth. In the Authority's judgment the needs case put

forward by NPg in respect of the Blyth scheme was poorly evidenced by NPg.

(v) The Authority does not agree that the solutions would not be applicable to NPg's network, and there was no evidence of this. Furthermore, the Authority does not accept that it is a proper challenge to a modelling process to seek to evidence a technical or commercial lack of feasibility in respect of a modelled saving after the event (where the lack of attributed saving in that category in the DNOs' own business plan had not been adequately evidenced). The Authority's modelling process looked at the greatest savings projected by any one DNO in each relevant category. Even if it were to be established (and in respect of NPg it has not) that there was a particular barrier to implementation of a particular solution by a particular DNO, savings can reasonably be expected to arise in that category from other solutions. For example, in the case of fault level reinforcement even if SSE's solution was for some reason inapplicable to NPg, as mentioned above there are other potentially applicable solutions.

(c) Second, the Authority does not agree that its approach to additional fault-level SGBs was erroneous:

(i) The Authority agrees that in order to assess the additional fault-level SGBs it selected the 75% mark of the best performing DNO's proportion of submitted net expenditure in fault-level reinforcement as the benchmark. The Authority judged an upper quartile not to be appropriate due to the small number of data points from which it would draw.

(ii) The Authority does not agree that it erred in its approach to zero returns by DNOs in respect of this category. The Authority reasonably proceeded on the basis that unless and until it had been explained and established to the Authority's satisfaction

why no SGB saving could or would arise for a particular DNO (in circumstances where a saving had been identified by at least one other DNO in the same category) there was no basis for the Authority to proceed on the basis that a DNO was unable to achieve a proportionate SGB saving. The zero returns in the business plans of NPg and others were not supported by evidence of sufficient consideration of SGBs. The Authority therefore disagrees that zero returns demonstrate areas of spending where smart solutions cannot sensibly be deployed, except in the case of SSEH which does not have any fault level reinforcement expenditure.

(iii) As to the example of Scottish Power in paragraph 6.92, the Authority does not consider that the identification of smart savings as between the two Scottish Power licensees assists NPg. Licensees that are part of the same DNO group can apportion costs and benefits between their licensees in different ways. This, and a range of other factors relating to processes, management and forecasts for each licensee may produce an uneven pattern of smart savings between two such licensees in any one category. The Scottish Power example does not demonstrate or indicate that savings by one DNO could not be replicated by others.

(iv) In all these circumstances, and in light of the lack of evidence of consideration of smart solutions and savings in relevant categories by NPG, the Authority submits that it was entitled to proceed on the basis that such savings identified by one DNO were open for adoption by other DNOs and, in particular, by NPg.

(v) As to paragraph 6.93, the Authority does not agree with NPg's characterisation of its approach. The Authority was not engaged in a general benchmarking exercise. Rather, it was seeking to assess the level of SGBs that could reasonably be expected to

arise by reference to DNOs' own plans. Under the relevant schemes providing public funding for the development of smart solutions a single DNO may run a particular project but the learning that arises from the project is shared with, and open for adoption, by the whole industry. SSE had demonstrated in its business plan it considered the matter carefully. By contrast, NPg and other DNOs provided the Authority with no evidence that they had considered smart savings in this area, nor any reasoned explanation why (if such was their position) analogous savings could not be achieved by those DNOs.

(vi) The Authority considers that the decision to adopt the approach it did rather than an upper quartile approach in respect of additional fault-level SGBs was a reasonable approach, which was open to the Authority for the reasons given and that NPg have identified no error in the Authority's approach.

(vii) The Authority considers for the reasons set out above that NPg's alternative approach, which would reduce the overall level of SGBs recognised in the category, would be unsuitable on the evidence the DNOs put forward to the Authority. Alternatively, even if NPg's suggested alternative approach would have been suitable that fact, if it were established, does not assist NPg to demonstrate any error in the Authority's approach and therefore does not assist NPg in this appeal.

(d) Third, the Authority disagrees that it erred in using SSE as the basis of calculation of fault-level reinforcement SGBs:

(i) There was no evidence before the Authority that the savings projected by SSE, which had led the publicly funded innovation trials in this field, could not be applied across the industry. The Authority notes that the Frontier report does not identify any basis to substantiate an argument to that effect.

(ii) The Authority does not therefore agree that SSE was an outlier.

(iii) The Authority does not agree that the level of a DNO's expenditure is, or is necessarily, relevant to the savings. The level of expenditure does not indicate the type of work planned to be carried out. Further, the majority of SSE's projected savings were not scheme specific savings.

(iv) The process on which the Authority was engaged was not a benchmarking exercise but rather a process of identifying the SGBs that the industry could reasonably be expected to benefit from over the price control period. The use of a 75% or upper quartile approach reflected the Authority's conservative approach in that it ensured that (a) the savings were not modelled on the basis of frontier data and (b) there was no double counting. There was, however, no obligation on the Authority to use a 75%, upper quartile or any other possible approach to establishing the level at which it ought to recognise likely savings.

168. As to paragraphs 6.96 to 6.106, the Authority does not agree that it erred in its approach to NPg's forecast SGBs in the general LV/HV reinforcement category, by reference to NPg's late identification, without adequate evidential support, that its submitted proposed expenditures already accounted for £18.7 million of savings arising from the use of smart solutions in general LV/HV reinforcement. Specifically:

(a) As NPg accepts at paragraph 6.100, in its business plan it did not identify and quantify the SGBs said now to amount to £18.7 million.

(b) NPg was given ample opportunity, in its business plans and in response to supplementary questions [**NPg/4/B/15-20**] to provide further information on SGBs. It did not quantify this sum until 29 August 2014, which was after it submitted its slow track business plan and then only following publication of Draft Determinations [**NPg/4/B/26**].

(c) At the time of this late submission, NPg suggested (in the letter identified at paragraph 6.101) that the saving could be seen from the difference between a forecast of prospective expenditure in its usual regulatory return to the Authority for 2012 on the one hand and NPg's business plan submitted to the Authority for approval at the fast track stage.

(d) In the Authority's judgment, there was no evidential support for the suggestion that the difference between these two figures related to SGBs. The Authority considered that a range of factors could have caused it: such as changes in forecasting due to the sensitivity of cost in this area to changes in load growth forecasts or refinement upon stakeholder scrutiny.

(e) In discharging its regulatory duty, including its obligation properly to safeguard the consumer interest, there was insufficient evidence and an insufficient basis for the Authority to accept NPg's suggestion referred to in (c) above to the effect that the comparison referred to therein reflected SGB savings already embedded within NPg's submitted costs.

(f) In respect of the quote at paragraph 6.96, save that by typographical error the quoted text should have referred to the change between NPg's 2012 forecast in its regulatory return and its fast track business plan, rather than between its fast-track and slow-track business plans, it is correct that the Authority concluded that there was a lack of evidence that the expenditure reduction related to SGBs. That conclusion was one that the Authority was entitled to reach on the basis of the material before it.

(g) In all these circumstances, NPg has identified no error in the Authority's approach whereby it did not recognise the suggested £18.7 million as relating to SGB savings already contained in NPg's projected costs.

(h) For the reasons set out above, the Authority does not agree that NPg demonstrated that the £18.7 million was contained within its projected

costs and there is therefore no basis for NPg to complain that it is being expected to make the same saving twice. To the extent that, despite that failure properly to evidence the same at the time, part or all of the £18.7 million did in fact form a part of NPg's submitted costings that does not amount to a sustainable ground of appeal. Responsibility for the consequences for its allowable costs of any failure by NPg adequately to evidence savings included in its original submitted costs rests with NPg and does not properly found any appeal against the Authority's approach or conclusion.

Alleged unfairness and failure to consult in the Authority's process

169. The Authority does not agree with the claim made at paragraphs 2.10 – and 2.11 and set out in paragraphs 6.107 – 6.123 that its process was unfair, whether as a matter of its approach to consultation or otherwise and rejects NPg's contention that its process was vitiated as a matter of law by any unfairness. The Authority disagrees with paragraph 6.107. As explained in the witness statement of Mr James Goldsack, the Authority's approach reflected the importance of SGBs and that importance was made clear to DNOs from the outset of the price control process and throughout. The Authority consulted on the methods by which it proposed to ensure that the allowances it fixed reflected a proper assessment of the SGBs which could reasonably be expected to arise. The Authority engaged with the DNOs on its approach in a number of ways and on various occasions, including through written publications, multilateral and bilateral meetings, workshops (including meetings specifically to address the issue of SGBs) as well as in correspondence and via written representations and suggestions received by the Authority from DNOs. The Authority's methodology was, perfectly properly, refined in consequence of the extensive engagement it undertook with DNOs. The relevant facts are fully set out in Mr Goldsack's statement.

170. By reference to paragraphs 6.108 and 6.110, although the Authority does not agree that the development of its approach, analysis and conclusions was subject to any formal legal duty of consultation at every stage of the price control process, the Authority agrees that it is good regulatory practice to

maintain a dialogue with licensed entities and explain the Authority's developing thinking during the course of a price control process. The Authority did so in this case, as explained in Mr Goldsack's statement.

171. As to paragraph 6.111, the Authority does not agree that any "legitimate expectations" arose from statements in the RIIO Handbook and the Strategy Decision. The approach anticipated by those initial publications was, as ought always to have been plain to NPg, subject to refinement as the process proceeded, not least as a result of ongoing engagement with DNOs themselves. In any event, those documents made clear that the Authority placed considerable emphasis on the importance of smart solutions and the proper reflection of SGBs in DNOs' business plans, as more fully described in the witness statement of Mr Goldsack.

172. As to paragraph 6.112(A), the Authority disagrees that NPg were not given sufficient opportunity to comment on the development and refinement of the Authority's approach to the assessment of SGBs throughout the course of the price control process. In particular, the Authority refers to:

(a) The Authority's engagement with NPg (and other DNOs) on the issue of embedded benefits to be recognised in their respective business plans.

(b) The workshops, meetings and correspondence between the Authority and NPg and other DNOs referred to in the witness statement of Mr Goldsack. In particular, the Authority made presentations to DNOs on two separate occasions on proposed changes to the Authority's methodology between slow track Draft Determination and Final Determination stages, with detailed slideshow presentations and an iterative process of engagement with DNOs in respect of any pertinent issues they wished to raise.

(c) The Authority's consultations and publications at each of the Strategy Decision, Fast Track and Slow Track Draft Determination stages, and the explanations of the Authority's approach (including developments

and refinements) and the opportunity for DNOs to comment thereon at each stage.

173. As to paragraphs 6.112(B) – 6.116:

(a) The Authority's definition of "smart" at Final Determination stage included the definition of smart at Draft Determination stage but was expanded to accommodate further savings in other categories outside of reinforcement. It became apparent that this was a necessary refinement as the Transform model only dealt with LCT reinforcement and is not therefore apt to cover all smart solutions, and associated SGBs, that will arise in other cost areas (and in which areas public funding had funded innovation).

(b) The Authority's proposed final approach was explained to DNOs in the period between Draft and Final Determination stage. In NPg's case, that approach was positive in that it led the Authority to recognise greater levels of embedded benefits within NPg's plan at the Final Determination stage.

(c) In any event, NPg has suffered no detriment, and its legalistic complaint is therefore academic, since the solutions and savings identified by NPg that were not accepted by the Authority were smart neither (i) under the definition applied at Draft Determination stage, nor (ii) under the refined definition applied at Final Determination stage.

(d) The Authority does not therefore agree that the putative "objection" referred to in paragraph 6.116 would have been a valid or well-founded one that would have led to any different outcome.

174. In respect of NPg's arguments on the treatment of specific projects at paragraphs at 6.117 – 6.123, the Authority responds as follows:

(a) First, NPg was given ample opportunity to provide sufficient evidence of the smart qualities of the projects to which it refers. However, NPg brought the Jarrett Street and Audby Lane projects to the Authority's attention only late in the process. Despite this, the Authority engaged

with NPg in respect of the projects, asking questions and requesting further information. The outcome of this process was that in the Authority's judgment the projects were not to be classed as smart.

(b) Secondly, that the Authority sought specific further information on the smartness of a particular set of *solutions* was a reflection of the significance of these solutions to the adjustments being made to DNOs' allowances and the Authority's recognition of the importance of therefore having high levels of certainty as to the levels of embedded benefits of each DNO in these areas.

(c) Thirdly, the expert review carried out was a part of a process of assessment by internal Ofgem staff and external consultants and was not a standalone expert review. There was therefore no standalone "expert review" to provide to NPg. As to paragraph 6.119, the Authority's review was based on a range of factors including other DNOs' practices, the Authority's expertise as the sectoral regulator and the information provided by DNOs. The assessment carried out was multifactorial and involved an exercise of judgment. The Authority reached conclusions as and when it felt able to do so, on the evidence before it, and it was under no legal obligation to engage in any additional rounds of information/evidence gathering. There was no legal error in the approach taken by the Authority.

(d) Fourthly, contrary to paragraph 6.120, WPD's savings were clear and well-quantified in its business plan. NPg's business plan, by contrast, did not provide adequate detail in this regard, and in certain cases where detail was provided it related to solutions which the Authority judged were clearly not smart solutions.

175. In all these circumstances, the Authority disagrees that there was any lack of fairness, whether in relation to consultation and/or the development, refinement and application of its approach and methodology during the price control process, or otherwise. The Authority does not agree that NPg has identified any basis on which the Authority's decision was vitiated by error of

law. Further, and in any event, NPg has not identified any basis for the grant of relief in relation to the unfairness it alleges.

PART V: GROUND 2 – REAL PRICE EFFECTS

Introduction

176. This ground of the appeal is a narrowly based challenge to certain aspects of the Authority's approach to the process of forecasting real price effects ("**RPEs**"), i.e. the prospective changes to external costs which a notionally efficient DNO is likely to experience over the 8 year price control period which are reasonably beyond their control, above or below RPI inflation assumptions.

177. The challenge only concerns (i) aspects of the process adopted by the Authority in respect of the "labour costs" component of RPEs which, as set out at paragraph 2.14, on average account for 66% of DNOs' costs, and (ii) the first 2 years of the period over which the assumption applies. Those years are 2014/15 (the year prior to the commencement of the price control period) and 2015/16 (the first year of the new price control period). The 2014/15 data is relevant because the RPE assumption rolls costs forward from the base year, which in this case was 2013/14.

178. The Authority submits that it adopted an approach which was both reasonable and amply justified and that NPg has failed to demonstrate any relevant flaw.

Context

179. By way of introduction:

(a) Under the RIIO model, allowed expenditures and allowed revenues are fixed at the outset of the price control period (though subject to certain mechanisms which provide for limited adjustments in light of actual data/performance over the period). The incentive properties of this ex ante approach are described in Part III above.

(b) Various elements of the calculations which produce the allowable sum therefore have to be *modelled* or *forecast* to arrive at what, in the Authority's expert judgment, it considers to be the best assessment of the reasonable, likely, prospective costs that DNOs will face and which the DNOs should, therefore, be entitled to recover from customers.

(c) Such a modelling and forecasting process is, by its nature, an inexact predictor of future reality, as any cost may transpire, in the event, to have been either higher or lower than first predicted by the process at the point at which recoverable expenditure is fixed at the outset of the 8 year price control period.

(d) That inexactitude is an inherent part of the process, which is (rightly) not challenged by NPg. NPg argued against adopting a process of RPE indexation which would have sought to assess RPEs annually rather than at the outset of the price control period **[RDB/ tab 15]**. The general process benefits DNOs, and consequently consumers, by reason of the certainty it provides. DNOs are able to plan investment and predict and manage commercial upside and downside factors. Consumers benefit from DNOs' ability efficiently to manage these factors and from more stable electricity charges.

180. DNOs' allowances are indexed by the Retail Prices Index ("**RPI**") as part of the price control framework. However, the Authority expects some of the costs faced by DNOs to change over RIIO-ED1 at a different rate than the RPI measure of economy-wide inflation. These differences in cost changes are referred to as RPEs.

181. Under the RIIO model, the Authority adjusts expenditure in the price control to take account of its forecast of the impact of RPEs [RIIO Handbook, paragragh 11.35, page 100]. The reason for this is to seek to reduce the risk to both DNOs and consumers that actual changes in the costs faced by DNOs will differ from the RPI measure of inflation. The Authority seeks to adjust for RPEs by providing an ex ante allowance based on its forecast of RPEs. Providing an ex ante allowance incentivises DNOs to find efficiencies because their allowances are fixed and they will keep a proportion of any savings they make and gives them predictability as to their revenues, supporting longer term investment decisions. Forecasting RPEs requires the Authority to make assumptions about how the prices of the goods that DNOs purchase may change over time.

182. The RPE forecast is constructed using actual price indices, forecast price indices and independent forecasts of changes in labour costs. The Authority applied the same RPE assumption to all DNOs in the slow-track process.

183. The pertinent example, in the context of NPg's challenge, is labour costs; the price of hiring and retaining staff.

184. NPg's grounds of appeal ignore what the *ex ante* allowance for RPEs is intended to achieve. NPg argue that the RPE allowance for labour should, to a greater degree, match the *costs incurred*. As stated previously, under the RIIO model the Authority sets an ex ante allowance which forecasts the costs that an efficient DNO is likely to face, and provides an incentive for the DNO to find savings. Using actual DNO costs instead of a forecast would risk funding DNOs for inefficient decisions – and if it became an established part of the process, would provide a perverse incentive for them to incur inefficient costs in the short term in order to increase the forecast, and therefore the future price control allowance.

185. NPg was well aware that the Authority considers DNO pay settlement data to be an inappropriate proxy for labour RPEs. NPg made the argument which it now advances in its appeal in the course of the previous price control process (known as DPCR5). The Authority's response to NPg's argument in DPCR5 was the same as its response during the RIIO-ED1 price control review process, and now in this defence, that DNO pay settlement data is inappropriate basis upon which to assess RPEs.

186. The Authority's forecast of RPEs formed part of its overall assessment of efficient costs. In respect of the RPE element of that process:

    (a) As part of its general cost assessment approach, each DNO's cost allowance is set through interpolation using a weighted average of 75 per cent of Ofgem's assessment of efficient costs and 25 per cent of the DNO's forecast.

(b) In order to protect consumers' interests the Authority used data in setting RPEs that were not available to the DNOs at the time they submitted their business plans.

(c) The Authority adjusted the IQI break-even point to avoid penalising any company inappropriately as a result of the RPE adjustment. This adjustment to the IQI break-even point forms part of BGT's appeal.

187. The Authority agrees with the factual background set out by NPg at paragraphs 2.13, 7.2, 7.9, 7.10, 7.11, 7.13, 7.14, 7.15 and 7.17.

188. The challenge which is advanced by NPg on the RPE issue is focussed on whether the Authority used inappropriate sources of data to reach its assessment of the likely RPEs over the price control period. At the outset the Authority observes that:

(a) There are a number of potential approaches and sources upon which the Authority *could* potentially have based its assessment of likely RPEs over the price control period.

(b) The Authority sought to identify what, in its expert judgment, it considered to be the most appropriate approach by reference to a range of factors, including the allocation of risks between consumers and network operators.

(c) The Authority formed a judgment as to what it considered to be the optimum approach and sources upon which to base its RPE analysis. NPg does not challenge in its appeal the bulk of the Authority's decisions on the proper approach and sources for forecasting RPEs (see, in particular, paragraph 7.12).

(d) The Authority considers that it is not sufficient on appeal for NPg to contend for a different approach, either in specific respects or in general, unless it can show (a) that the approach adopted by the Authority was *wrong* and (b) in any event, that any substantiated error was material in the overall price control exercise with which the Authority was engaged. The test of whether the Authority was wrong to

adopt the approach it did is whether it was wrong *by reference to the circumscribed statutory grounds of appeal*, not whether some other different approach could have been adopted. The Authority has set out more fully in Part II above 2 its views on how the CMA should approach the question of whether the decision is *wrong*.

Central complaint that the Authority ought to have set RPEs by reference to DNOs' own pay settlement data

189. In relation to NPg's central complaint in respect of the Authority's approach to RPEs, as articulated at paragraphs 2.14 and 7.16, namely that in respect of the labour component of the RPE adjustment for the years 2014/15 and 2015/16 the Authority should have used data on DNOs' actual pay settlements, the Authority responds as follows:

(a) The Authority notes that the challenge is focused only on the first and second year over which the assumption applies. No challenge is adopted to the Authority's approach for the 6 years from 2016/17 onwards and the challenge to the Authority's conclusions in respect of the year 2015/16 impermissibly rely, as set out in more detail below, on data which (a) were not available at the time the Authority reached its decision and (b) may still not be available in full.

(b) In respect of the 2014/15 period (and to the extent that the CMA concludes, contrary to the Authority's submission, that the argument is also relevant to the 2015/16 period) the Authority does not agree that DNOs' pay settlements constitute data that the Authority was wrong not to use in making assumptions about RPEs:

(i) First, the Authority's task was to adjust costs for real price effects to reflect external cost pressures on DNOs outside of their control. As the Authority stated at paragraph 12.32 of its Final Determinations for the Slow-Track Electricity Distribution Companies – Business Plan Expenditure Assessment, "*The RPE assumption is <u>not intended to match the costs that DNOs will, or have actually, faced. Rather it is intended to reflect the</u>*

external pressures on costs, relative to economy-wide inflation, that are outside of their control." (emphasis added)

(ii) Second, DNOs' own pay settlement data is at one step removed from the actual cost pressure (being relevant labour market costs). Pay settlement data does not constitute an underlying pressure; rather it represents the decisions DNOs take to *deal with* or address those underlying cost pressures. The Authority therefore, entirely appropriately, concluded that pay settlement data is not a "*close proxy*" for labour cost inflation or, alternatively, not a close enough proxy to warrant using pay settlement data instead of the Authority's preferred sources of data.

(iii) Third, setting RPEs according to *actual* DNO pay settlement data is potentially in tension with the principles of incentive-based regulation and carries a clear risk of perversely incentivising DNOs. If the Authority were to start basing its approach to labour RPEs on DNOs' pay settlements this could operate to loosen the incentives on DNOs properly to control labour costs, as they would be able to recover those costs 'onward' from consumers.

(iv) In those circumstances, the Authority properly and reasonably declined to base its assessment of RPEs in 2014/15 on DNOs' own pay settlement data.

190. The Authority's approach, in accordance with its principal objective as regards the interests of existing and future consumers, was to set RPEs with a view to the wage growth that a notionally efficient DNO could be expected to incur, rather than on the basis of actual pay settlements agreed by DNOs. The Authority took this approach at each of the RIIO price controls and at the previous electricity distribution price control, DPCR5 (see the executive summary of the CEPA report, Update of Input Price Inflation Forecasts for DPCR5, November 2009 **[RDB/tab 1]**. A number of sources of reputable data

allowed the Authority to make a proper and appropriate assessment, as part of its forecasting process, of likely future labour cost changes so as to be able to adjust DNOs' allowable costs to reflect these anticipated RPEs.

191. In forecasting RPEs the Authority has access to relevant, independent data and it reached the judgment that it was appropriate to use that data and not to use comparative benchmarking of DNOs' own pay settlement data to set the RPE allowance. The Authority relies on comparative benchmarking where relevant and independent data is not available but this is not the case for setting the RPE allowance. The Authority's judgment was that forward-looking RPEs are best assessed against other market indicators. That judgment was a perfectly rational and appropriate one.

192. Contrary to the assertion at paragraph 7.19, the decision to treat RPEs differently from other cost categories, in not subjecting them to comparative benchmarking, was consistent with (i) the approach that the Authority stated it would adopt at the outset of RIIO-ED1 in its strategy decision [Vol 1/Tab B/Tab 9] and (ii) the practice in respect of previous price controls, including previous RIIO price controls for other sectors and the previous electricity distribution price control, DPCR5.

193. NPg refers to the decision of the CC in the Northern Ireland Electricity Limited ("**NIE**") case, which concerned a reference to the CC of NIE's rejection of draft modifications to its licence to reflect a price control determination issued by the Northern Ireland Authority for Utility Regulation. As to that case, the Authority makes the following observations:

(a) Whilst it is correct that the CC in the NIE case used DNOs' pay settlement data to derive an RPE assumption for NIE, the Commission specifically did not use NIE's *own* pay settlement data and confined its consideration to DNO pay settlements in Great Britain so as to exclude NIE/Northern Ireland from the analysis.

(b) By contrast, NPg's case appears to be that the Authority ought to have used the average of DNOs' pay settlement data in its analysis (see

paragraph 4.95 of the Frontier Report), which would therefore include NPg's *own* pay settlement data.

(c) The CC in the NIE case also made an adjustment to the value it derived from DNOs' pay settlement data based on information from the ONS' Annual Survey of Hours and Earnings ("**ASHE**") data.

(d) By contrast, NPg fails to acknowledge the adjustments the CC made to address some of the issues with using only pay settlement data to set the labour RPE.

(e) The Authority does not consider NPg's proposed approach to be *an* appropriate, still less *the most appropriate*, way to proceed.

(f) The Authority does not, in any event, accept that the CC's approach amounts to any form of binding regulatory precedent. The CC has taken different approaches to the setting of RPEs in different previous regulatory appeals. In addition, the context of the NIE case was also different. That case was concerned with the identification of an appropriate RPE for a single business with no exact comparators; NIE was the only Northern Irish DNO. By contrast, in the present case the Authority was required to determine the appropriate RPE for a group of comparable GB DNOs. As stated above, NPg's appeal challenges the Authority's decision not to use GB DNOs' pay settlement data *including* NPg's own pay settlement data. However, even if the Authority were to have applied a variant of the CC's approach in the NIE case, in setting the RPE at the level of average GB DNO pay settlements (*excluding* the particular DNO in question) the Authority considers that this would still risk seriously weakening the incentive on all DNOs to achieve the most efficient pay settlements, as they would collectively benefit from a tacit relaxation of proper control of inflationary labour cost pressures.

Challenge to the adequacy of the Authority's reasons for not using DNOs' pay settlement data

194. The Authority does not agree with NPg's claim that it did not present an adequate basis for not using DNOs' own pay settlement data for 2014/15

labour cost RPE assumptions. In response to the specific points in, inter alia, paragraphs 2.15, 7.4(A) and 7.20 – 7.22, the Authority submits as follows:

(a) As the Authority set out at paragraph 12.32 of its Final Determinations for the Slow-Track Electricity Distribution Companies – Business Plan Expenditure Assessment, use of DNOs' pay settlement data would risk leading consumers to pay higher prices on account of inefficient pay deals:

(i) The Authority accepts that DNOs in principle have their own incentives to seek to obtain efficient pay settlements in that they will retain a proportion of any efficiency that they achieve.

(ii) However:

(1) the Authority has a responsibility in the consumer interest to appropriately balance risk between DNOs and consumers and cannot therefore simply proceed on a base assumption that DNOs are both motivated to and *in fact achieve* efficient pay settlements; and

(2) if the Authority were to start basing its approach to labour RPEs on DNOs' pay settlements this could operate to loosen the incentives on DNOs properly to control labour costs, as they would be able to recover those costs 'onward' from consumers.

(iii) The Authority therefore reached the reasonable and appropriate judgment that to use DNOs' own pay settlement data would not reflect an appropriate balance of risk and incentive between consumers and the DNOs.

(b) With respect to the CC's decision in the NIE case:

(i) The Commission rejected the use of NIE's pay settlement data on the basis that two identified disadvantages outweighed any advantage in using NIE's own data. The Commission identified

the two disadvantages at paragraph 11.52 **[NPg/6/B/23]** of its Final Determination:

(1) First, that "*NIE's settlements represented only a partial measure of its labour costs as they did not properly capture the price of bought-in labour, for example subcontractors*"; and

(2) Second, that "*using NIE's settlements would amount to a straight pass-through of actual wage settlements to consumers. Taking a pass-through approach would introduce the risk that a company could be rewarded for inefficient wage settlements*." The Commission therefore concluded, at paragraph 11.53, "…*these two disadvantages were significant enough that it would not be in the public interest to use NIE's own wage settlement data as a basis for setting the historic estimate for labour inflation*."

(ii) NPg does not specify that to which it is referring when it says that the CC in *NIE* found a "*method of mitigating*" the risk that the use of actual pay settlement data might reward inefficiency:

(1) The Authority assumes that NPg is referring either to the Commission's approach of looking at DNO pay settlement data rather than relying on NIE's own pay settlement data or to the Commission's use of the ONS' Annual Survey of Hours and Earnings ("**ASHE**") data alongside DNOs' pay settlement data to make a reducing adjustment when setting the historic labour RPE for NIE.

(2) In response to the former, the Authority does not agree that this is an appropriate approach for the reason set out in paragraph 193(f) above.

(3) In response to the latter, as a matter of principle, this approach would only serve to reduce rather than eliminate the identified disadvantages.

(4) Furthermore, the Authority does not consider either approach to be justified in this case when other independent data exists which does not suffer from the disadvantages identified by the Commission in sub-paragraph 198(b)(i) above.

(c) With respect to the issue of sub-contractors, the Authority does not agree that DNOs' own pay settlements are the best proxy for changes in the rate of pay of such workers. As NPg acknowledge at paragraph 94 of the witness statement of Mark Drye, "*[w]e do not have visibility over the pay awards made by our contractors to their staff*". The reliance at paragraphs 94 to 95 of Mr Drye's witness statement on the price increases NPg has incurred in respect of its identified major service contracts is not apt to constitute a reliable measure of changes in sub-contractor labour costs. This is because the increased costs are not necessarily or in any well-defined way linked to wage costs and may reflect a range of factors or simply that there is insufficient competition in the marketplace to prevent sub-contractor companies from increasing their own profit margins. The Authority's concerns that reference to DNOs' own pay settlement data would not capture an important part of the workforce therefore remain apt and would not be assuaged by the approach now suggested by NPg.

(d) The Authority has considered the argument raised by NPg, in response to the Draft Determination, [**NPg/2/B/23/paras. 42-45, and 87-88**] that continuously employed staff enjoy generally higher wage growth. This argument was made by NPg by reference to certain data from the ONS. In response:

(i) The Authority rejected the argument, and declined to change its approach, on the basis that:

(1) NPg had not provided the Authority with evidence that its workforce disclosed a higher percentage of continuously employed staff (after the event, NPg now says that 93% of its staff are continuously employed, compared to 79% in the general wider economy); and

(2) Although the Authority recognised, more generally, that there had been certain structural changes to the labour market, particularly in recent years, which have had an impact on the make-up of labour input price indices, NPg had not put forward a persuasive case that they had been impacted differently than the general labour market nor sought to quantify any alleged differential impact (see paragraph 12.31 of the Authority's Final Determinations for the Slow-Track Electricity Distribution Companies – Business Plan Expenditure Assessment).

(ii) The problems of quantification of the impact of structural changes in the labour market (noting that NPg's case only considers a narrow view of any structural changes predicated on a single piece of evidence covering a limited time period) were recognised in the NERA report **[RDB/tab 13]** submitted on behalf of all slow-track DNOs, which stated at section 2.2.3, on the subject of the impact of composition of employment changes in the economy on DNOs, "*[the] extent DNOs experience different composition change to the overall economy is difficult to assess*".

(iii) In these circumstances the Authority reached the reasonable and appropriate judgment that the argument about continuous employment did not necessitate any change of approach in favour of using DNOs' own pay settlement data in assessing RPEs.

Challenge to the Authority's approach and data sources

195. The Authority does not agree that the data it used did not reflect the labour costs faced by the Appellants. With respect to the specific points made in, inter alia, paragraphs 2.16, 7.4(B), 7.6, 7.7, 7.16, 7.19 and 7.25 – 7.27:

(a) In reaching its judgment on the appropriate labour component RPE adjustment, the Authority considered evidence on how the costs of labour had changed in the past and how they might be expected to change in the future. The Authority used the indices identified at paragraph 7.17 to inform its assumptions, namely:

(i) The Office of National Statistics' Average Weekly Earnings index for the private sector;

(ii) HM Treasury consensus forecasts;

(iii) The British Electrotechnical and Allied Manufacturers' Association ("**BEAMA**") Electrical Labour index; and

(iv) The Building Cost Information Service ("**BCIS**") Civil Labour (Labour and Supervision in Civil Engineering) index.

(b) These indices constituted a range of reputable and appropriate data sources from which the Authority could reasonably draw for the purpose of forecasting RPEs. The Authority notes that the aforementioned identified sources include sources which were referred to and relied upon both by NPg and by other DNOs, as follows:

(i) The NERA report, which formed a part of NPg's business plan, **[RDB/tab 4]** used the BEAMA index.

(ii) The Authority's final proposals for National Grid Electricity Transmission's (NGET's) current price control (RIIO-T1) **[RDB/tab 3]**, which was relied on by NPg in setting its business plan, used both the BEAMA and BCIS indices. The Authority's use of these indices is established practice and the use of the BEAMA index was specifically supported by NGET in RIIO-T1.

(iii) The First Economics report which formed a part of the business plans of SPEN, WPD and SSE also relied on the BEAMA index.

(c) The Authority does not understand how NPg can fairly criticise as unrepresentative data upon which it has itself relied.

(d) The Authority considered both the wider market for private sector industries and more specialist indices for electrical labour. The Authority does not agree that its use of labour data covering areas other than electricity distribution was not fit for its purpose of identifying the costs pressures faced by DNOs. In particular:

(i) If the Authority had used data that only reflected the costs of the electricity distribution sector, this would have amounted to a simple pass through of DNOs' costs incurred, rather than the Authority reaching a considered judgment on the RPEs which DNOs were most likely to face on an ongoing basis.

(ii) As DNOs have significant influence on the costs of the electricity distribution sector, to confine labour cost analysis for the purpose of setting RPEs to the narrow set of DNOs' own pay settlement data would weaken the incentive on DNOs properly to manage these labour costs.

(iii) The Authority considers that it was reasonable and appropriate to take into account private sector labour market data (relating both to general labour such as administrative and head office staff and specialist electrical labour). The Authority set two RPE assumptions for labour; one for general labour and one for specialist labour. The general labour RPE was based on private sector labour market data. The specialist labour RPE was based on market data for more specialist industries. In the Authority's judgment the indices used for the specialist labour RPE assumption represent the electrical labour market from which DNOs will draw their labour, noting that part of DNOs' allowable revenues (identified by benchmarking DNOs' own submitted

costs) represent the costs they will face in training newly recruited staff and in up-skilling existing staff. The proportion of the total work force in, respectively, the general and specialist labour categories was based on DNOs' business plan submissions.

(iv) On the basis of those multiple sources, the Authority identified proxy information which represented a market for labour which in its judgment provided an appropriate and reasonable assessment of the costs of labour faced by DNOs.

(e) NPg did not suggest in its business plan, and does not suggest now in its appeal, that the Authority should have used any other alternative proxy to the indices relied upon. It simply makes the argument that the Authority should have used DNOs' own pay settlement data.

(f) The Authority has always acknowledged that a range of *potential* data sources exist from which it might in principle draw to inform its RPE assumptions. As set out at paragraph 12.32 of its Final Determinations for the Slow-Track Electricity Distribution Companies – Business Plan Expenditure Assessment, the Authority stated, "*We recognise that other evidence exists but consider the indices we have chosen to be robust and representative of the wage growth that a company like a DNO may face.*" However, the fact that other potential data *could have been used* does not mean that the Authority was wrong to use the data sources that it did. The Authority was entitled to conclude, in the exercise of its expert judgment, that its final selection of data sources was an appropriate one. NPg has failed to demonstrate this to be an unreasonable or in any way erroneous judgment.

(g) The indices to which the Authority had regard in reaching its conclusion on the appropriate RPE adjustment were all impacted, in different ways, by the recession, and the Authority does not accept that they were in any sense "*manifestly inadequate proxies*" for labour market inflation as alleged at paragraph 7.27:

(i) This claim was not made at the Draft Determination stage, nor is any operative challenge advanced in respect of the use of these proxies for the years from 2016/17 onwards.

(ii) The argument is predicated on the assertion, which the Authority did not and does not accept, that DNOs' labour costs were not affected by the recession. The Authority does not consider that pay settlement data provides reliable evidence of the characteristics of the relevant underlying labour market. Thus, neither NPg nor the DNOs in general made good the assertion that their labour costs were unaffected by the recession, or any argument that there is a scarcity of suitably qualified labour (both as a matter of existing skill sets within the labour pool and as to the potential to train new staff or upskill existing staff), in the evidence they produced to the Authority.

(iii) The Authority also observes that its use of specialist electrical labour indices is apt to capture any differential recessionary impact by *sector*. For example, in the period 2008-2009 to 2013-14, general ONS private sector labour costs data showed a real terms decrease of 7% over the period (comparable to the change to the BCIS index), however the BEAMA electrical labour index only showed a real terms decrease of 2%.

(h) The Authority notes that the amounts DNOs are allowed to recover in the year 2014/15 do not relate to the current price control period, as they were set in the previous price control review (DPCR5). The identification of the appropriate RPE adjustment for 2014/15 is only relevant to the present price control period (RIIO-ED1) to the extent that it informs calculations which carry over into the years which are subject to this price control period.

(i) Contrary to the assertion at paragraph 7.19, the Authority does not agree that its approach is fairly to be characterised as risking "stranding" costs for the industry:

(i) Under the RIIO price control system it is a matter for the DNOs to determine how to invest to deliver the necessary outputs as efficiently as possible.

(ii) Whilst there is necessarily upside and downside risk which acts as an incentive on DNOs properly to manage costs, the Authority does not accept that its approach will lead to any properly recoverable cost being rendered irrecoverable.

(iii) The Authority does not accept the arguments put forward at paragraph 7.25. Whilst the explanation set out there may explain demand side factors for relevant employees, the explanation does not engage with supply side factors.

(iv) More generally, whilst the explanation put forward (decarbonisation and the volume of investment projects) might explain why the size of DNOs' workforces may not have decreased during the recession, it does not explain why this would have the effect of leading DNOs to pay above market rates of pay.

(v) Neither NPg nor any other DNO has made out a persuasive case of a supply side unavailability of staff. The specialist nature of part of DNOs' workforces was already accounted for by reference to the specialist labour indices to which the Authority had regard in its analysis.

Other arguments

196. The Authority does not accept that it was under any obligation to undertake a form of comparison of its RPE determination against DNO's historic pay settlement data as a form of so-called "reality-check", contrary to the suggestions in paragraphs 2.17 and 7.24 – 7.25. This "reality-check" suggestion is no more than a reiteration of the argument, already addressed above, that the Authority ought to have had regard to DNOs' pay settlement data. As set out above, the Authority does not agree that DNOs' pay settlement data is a reliable guide to the costs that a notionally efficient DNO

in fact faces and thus did not analyse differences between pay settlement data and calculated RPE assumptions for the price control period, which NPg now seeks to characterise as "divergence". In the course of determining the appropriate RPE adjustments to be made, the Authority looked at a range of evidence in order to select appropriate proxies for labour market cost pressures. Some of the evidence pointed to higher RPEs and some to lower RPEs.

197. The Authority disagrees with the criticism of its approach to fixing RPEs for the period 2015/16:

(a) By way of introduction on this point, the Authority notes that:

(i) 2015/16 data was not available to it at the time it reached its determination; and

(ii) the RPE process is a forecasting process which uses best available data to forecast *likely* future costs.

(b) As a matter of principle, the Authority does not accept that it is permissible to use ex post facto evidence of actual pay settlements in 2015/16, as a basis to challenge the forecast labour costs arrived at before the availability of such data.

(c) By reference to paragraph 7.7, the Authority disagrees as a matter of logic with the suggestion that the Authority made an "*error*" in respect of its approach to 2015/16 since, as NPg itself acknowledges, the data upon which it seeks to rely to substantiate the purported error was not available to the Authority at the relevant time.

(d) For these reasons the Authority does not accept what is set out in paragraphs 2.18, 7.6 and, in material part, 7.7.

(e) With respect to paragraphs 2.19, 7.6 and 7.28, the Authority accepts that it made RPE assumptions for 2014/15 and 2015/16 but does not accept that it has materially understated the RPEs faced by NPg.

(f) The Authority also does not accept that it would be appropriate for the CMA or the Authority on remission, if any part of NPg's appeal on this ground was upheld, to have reference to any 2015/16 data which might be available by that point. To do so would perversely incentivise DNOs to appeal against RPE determinations in circumstances where any actual future data which was not available to the Authority at the relevant time is or is thought likely to be more favourable to a DNO than the assumptions upon which the Authority's decision was based.

198. As to paragraphs 2.20 and 7.5, the Authority does not accept that it has made a material underfunding error, that it has failed to have regard or give appropriate weight to its principal objective and duties, that its determination was based on errors of fact or that it acted in error law in any of the ways alleged. The Authority submits that NPg has failed to identify how the limited criticisms which it makes of the Authority's overall approach to the assessment of RPEs relate to the various legal grounds set out in paragraph 2.20.

199. In response to NPg's practice of cross-referencing in parts of the Notice of Appeal to large sections of witness statements and expert reports, in summary (and without admission of any point not referred to) the Authority responds as follows:

(a) In respect of the reference at paragraph 7.3 of the Notice of Appeal to paragraphs 4.1 – 4.22 of the Frontier Report exhibited to the witness statement of Michael Huggins:

(i) The background at paragraphs 4.1 – 4.8 is agreed.

(ii) Contrary to paragraph 4.9, the Authority did not rely only on general labour cost indices. It also had regard to specialist indices, as set out above.

(iii) For the reasons set out above, the Authority does not agree that its approach was wrong or otherwise legally impeachable. On the contrary, its approach was reasonable and appropriate.

(b) In respect of the reference at paragraph 7.25 of the Notice of Appeal to paragraphs 4.80 – 4.84 of the Frontier Report:

(i) The Authority does not accept that industry totex (i.e. total expenditure) is a reflection of DNOs having been unaffected by the recession. Totex is impacted by both volume and cost of work and the Authority notes that the Frontier analysis does not isolate one from the other.

(ii) In general, given that DNOs employ a range of different types of employees, the Authority does not consider that the DNOs have made good the contention that there has been demand pressure for all types of employees such as to remove any recessionary impact.

(iii) Even if there are demand side factors supporting wages in the sector, the DNOs have not previously and the Frontier report does not now address supply side factors. The Authority does not accept that DNOs (which are on any view substantial corporate entities) cannot train other existing labour market candidates if they experience demand side pressure with the effect of supporting wage growth.

PART VI: GROUND 3 – REGIONAL LABOUR COST ADJUSTMENTS

Introduction

200. This ground of appeal is a narrowly based challenge to aspects of the Authority's approach to taking account of regional differences in the cost of labour between London, the South East and the rest of Great Britain ("**RLCDs**") in adjustments to the costs submitted by DNOs.

201. In particular, NPg's challenge concerns:

(a) the basis on which the Authority arrived at the RLCDs;

(b) the adjustments made to the DNOs' submitted costs ("**Regional Labour Cost Adjustments**" or "**RLCAs**") based on the RLCDs.

202. The Authority submits that it adopted an approach which was rational, lawful and amply justified and that NPg has failed to demonstrate any relevant flaw in the approach adopted.

Context

203. The Authority agrees with the factual background set out by NPg at paragraphs 2.21, 8.1, 8.9, 8.11, 8.12, 8.13, 8.14, 8.15, 8.16, 8.17 and 8.19.

204. Under the RIIO price control system, DNOs submit business plans to the Authority which contain detailed costs predictions for the period of the RIIO-ED1 price control. The Authority then makes certain adjustments to the submitted costs before the data is entered into comparative benchmarking models. One of the adjustments made at this stage is the RLCA.

205. The RLCA was made based on data on RLCDs from the Office of National Statistics' ("**ONS**") Annual Survey of Hours and Earnings ("**ASHE**") dataset for the period 2008 – 2012. Data taken from that dataset was used to create Regional Labour Cost Indices ("**RLCIs**") which were, in turn, used to assess the extent of the RLCA to be made. The Authority used data collected from the DNOs to select which occupation data to include in the RLCIs.

206. The ASHE dataset classifies the result of the ASHE on a Standard Occupational Classification ("**SOC**") basis. SOC is a common and well

established classification of occupational information for the UK. Occupations are classified in terms of their skill level and skill content and are aggregated by reference to similarity of qualifications, training, skills and experience of the relevant tasks. The SOC is a hierarchical structure.[48] The current SOC2010 classification is made up of the following levels by which the disaggregated categories are organised:

(a) nine "major group" (1-digit SOC codes) categories; under which sit

(b) 25 "sub-major" groups (2-digit SOC codes); under which

(c) 90 "minor" groups (3-digit SOC codes); under which

(d) 369 "occupational unit" groups (4-digit SOC codes), being the smallest unit of classification.

207. With respect to these SOC codes:

(a) 1-digit SOC codes therefore represent a relatively small number of groups that are general in nature with larger sample sizes, whereas 4-digit SOC codes are more specific, with a much larger number of groups, and a smaller sample size.

(b) The challenge advanced by NPg is focussed on whether the Authority chose the correct level of SOC code for use in its RLCAs. NPg do not challenge the fact that the Authority used the ONS' ASHE data (see in particular 8.21(A) and (B)). Its challenge is, as noted above, a very narrow one and is focused on the use of a small number of 4-digit SOC codes.

(c) The Authority chose to use data from the ASHE dataset at the 2-digit SOC code level. It did so in order to strike a balance between using data which contained relevant occupations on the one hand and avoiding small sample sizes on the other. The Authority did not use 4-digit SOC codes because that would have given rise to problems deriving from data with small sample sizes and industry bias (i.e.

[48] The hierarchical structure is set out in ONS, Standard Occupational Classification 2010 – Volume 1: Structure and description of unit groups, 2010 **[RDB/tab 2]**

samples which contain a disproportionately high ratio of DNOs' own employees).

208. The Authority considers, and submits, that it adopted an approach that was both reasonable and amply justified and that NPg has failed to demonstrate any relevant flaw in the approach it used.

209. There is a relatively small number of approaches upon which the Authority could potentially have based its assessment of RLCDs and, consequently, RLCAs over the price control period. The Authority sought to identify what, in its expert judgment, was the most appropriate approach by reference to a range of factors, including the objectivity of the data and the need to achieve a balance between the risks associated with using too small a sample size and the relevance of the information selected.

210. The RLCAs are used as part of the process of Ofgem reaching its overall view on the level of efficient costs for the companies. In setting the revenue allowance this is then interpolated to allow the company 25% of its view on efficient costs and 75% of the Ofgem view. The Authority's calculations are that using the 4-digit SOC codes, as proposed by NPg, in its RLCAs would give an additional £1.5m additional revenue allowance which, at around 0.05% of the Final Determinations allowance, is immaterial.

211. It is not sufficient on appeal for NPg to contend for a different approach, either in specific respects or in general, unless it can show (a) that the approach adopted by the Authority was *wrong* and (b) in any event, that any substantiated error was material in the overall price control exercise with which the Authority was engaged. The test of whether the Authority was wrong to adopt the approach it did is whether it was wrong *by reference to the statutory grounds of appeal*. The Authority has set out more fully in Part II above its views on how the CMA should approach the question of whether the decision was *wrong*.

212. The Authority submits that it adopted an approach which was rational, lawful and amply justified and that NPg has failed to demonstrate any relevant flaw in the approach adopted.

Central complaint that the Authority ought to have set RLCDs and consequently RLCAs by reference to more granular data

213. In relation to NPg's central complaint in respect of the Authority's approach to identifying RLCDs and RLCAs, as articulated at paragraphs 2.22, 2.23 and 8.18, namely that in respect of the RLCDs the Authority should have used 4-digit ASHE data (8.21(A)), the Authority responds as follows:

(a) The Authority notes that, although NPg refers to the possibility of using alternate data sources, it does not take issue with the use of data from the ONS ASHE dataset.

(b) The Authority does not agree that the 2-digit data upon which it based its analysis was inaccurate, whether because the results were distorted by mix or compositional issues or otherwise:

(i) First, in selecting which level of data to use in assessing RLCAs, the Authority considered in this case that data on 4-digit SOC codes carries with it an inherent risk of small sample sizes providing unrepresentative data. It also considered that such data also gives rise to the possibility of 'industry bias' in that any differences in pay specific to DNOs may be reflected disproportionately in data with a small sample size. By way of example, in 2012 ONS estimated that there were 21,000 estimated employees in the population for the ASHE data set at the 4-digit SOC code level for electrical engineers (SOC 2123). The sample used for the ASHE is based on a sample of 1% from employee jobs from HM Revenue & Customs (HMRC) Pay As You Earn (PAYE) records.[49] In their response to Ofgem's data request on the number of full time equivalent employees ("FTEs") in each SOC code, DNOs reported employing almost 2,400 FTEs in the SOC code 2123. In other words, assuming a random sampling process, over 10% of the occupational wages within that code category may have been set by the DNOs. The

[49] ONS, Quality and Methodology Information, Annual Survey of Hours and Earnings, Low Pay and Annual Survey of Hour and Earnings Pension results, September 2014, page 1 **[RDB/ tab 14].**

Authority considers that using data that was overly influenced by DNOs would be inappropriate as that data would reflect, and therefore (by the reliance placed upon it) perpetuate, any inefficiencies in the DNOs' own wage setting relative to the general labour market. For example, if a DNO paid its workers 10% more than the UK average, but living costs and their productivity did not justify this, this ought properly to be considered to be a unit cost inefficiency rather than a regional labour cost differential (RLCD) which the DNOs can properly pass on to consumers through regulatory price control process.

(ii) Using a 2-digit SOC code strikes a better balance between including relevant occupations which are not necessarily directly related to the DNOs' business, and avoiding the above issues in respect of sample size and industry bias.

(iii) Second, NPg argues that the ONS ASHE data suffers from compositional issues. However, such issues can and do exist at all levels of data. Using NPg's own example of Michelin chefs to illustrate this point: there are more Michelin chefs in London, which leads to an effect on the mean wages in London, which it says is a compositional issue. However, the relevant 4-digit SOC code incorporating data on Michelin chefs aggregates such data with data on other chefs, thus creating the alleged compositional error which NPg asserts exists in the 2-digit SOC codes. NPg fails to explain why its proposed 4-digit SOC codes do not suffer from compositional issues. Applying the same reasoning to compositional issues in relation to an example of relevant labour costs in this sector, the 4-digit SOC code 5249 (Electrical and electronic trades n.e.c.), which was presented by NPg as an appropriate alternative to Ofgem's use of 2-digit SOC codes, includes overhead line workers. This SOC code is also therefore likely to suffer from compositional issues. This is because overhead line workers are included in this SOC code

but London is predominately an underground network, the London region therefore has proportionately fewer overhead line workers than other regions.

(iv) The Authority notes that NPg have selected just 13 of a wider group of 34 4-digit SOC codes (which it says suffer less from compositional issues). However, these 13 SOC codes (a) show a lower average RLCD than the remaining 21 and (b) the Authority considers that the majority do not reflect the DNOs' workforce [**CB/2**].

(v) In these circumstances, the Authority was entitled to base its assessment of RLCDs and RLCAs on 2-digit SOC code ONS ASHE data. Certainly, it was not 'wrong' to do so, which is what matters for present purposes.

Complaint that the Authority failed to explain why it used 2-digit SOC codes

214. NPg suggest that on being challenged on its use of 2-digit SOC codes, the Authority failed to explain why it used those codes. That suggestion is misplaced.

215. The Authority makes the following observations:

(a) NPg raised these issues at various stages, including:

(i) In slides presented to the Authority on 16 September 2014 and 17 October 2014 [**NPg/6/B/30** and **NPg/6/B/37**]:

(1) The evidence provided on 16 September 2014 promoted the use of much tighter defined occupations.

(2) The evidence provided on 17 October 2014 referred to 1 digit SOC codes only and did not promote the use of 3- or 4-digit SOC codes.

(b) The Authority considered that the representations made in the slides and correspondence and in meetings did not demonstrate that 1-digit or

4-digit SOC codes were free from similar or greater potential compositional issues than NPg argue are present in the 2-digit SOC code data. Nor was it persuaded that it was wrong to maintain its proposed reliance on 2-digit SOC data.

(c) Accordingly, in the Final Determination cost assessment [**NPg/1/B/16/paras. 11.26-27 and para 4.17**], the Authority stated "*We do not consider that the compositional issues evidence presented by one DNO [NPg] demonstrates that the ONS data does not reflect DNOs' regional wages. The use of ONS data is in line with our previous price controls and with the Competition Commission's final determinations for Northern Ireland Electricity Ltd price control and Ofwat's PR14.*"

Complaint that the Authority should have used 1-digit SOC codes

216. This argument was presented by NPg in slides at the Draft Determination stage dated 17 October 2014 [**NPg/6/B/37**] and in the Notice of Appeal.

217. In its slides, NPg referred to 1-digit SOC code categories in support of its contention that the RLCD for London should be 11 – 15% and for the South East 0 – 4%. NPg then proposed the use of 10% for London and 0% for the South East.

218. The Authority took (and still takes) the view that 1-digit SOC codes are too general to be appropriate for use in the RLCD analysis. The Authority is not aware of any similar exercise undertaken by other authorities in which those authorities considered it appropriate to use 1-digit SOC codes, and NPg does not appear to have identified any such example.

219. The Authority notes that NPg appears to be inconsistent in its approach. On the one hand it seeks the use of 4-digit SOC codes on the basis that the information is more specific, whereas 2-digit SOC codes are, so it is said, insufficiently specific. On the other hand, it has also advocated using 1-digit SOC codes, despite that data being more general than the 2-digit SOC codes.

220. On this basis the Authority submits that NPg has failed to demonstrate any relevant flaw in the approach adopted.

Complaint that the Authority could have adopted the approach taken by Ofwat to include regional labour cost variables in the modelling rather than as a separate adjustment

221. NPg seeks to argue that the Authority could have adopted the same approach as Ofwat adopted in the price control process of regulated water companies, which was to include a variable for regional labour costs in the regression modelling stage, rather than to make a separate adjustment. NPg advances the argument that this would have allowed the Authority to *"test the quality of the regional wage variable as a factor explaining the observed variations in wages".*[50]

222. The Authority takes the view that Ofwat's approach was not a viable alternative. Regression based modelling is a statistical process for estimating the relationships among variables. In the Authority's judgement, regression based modelling was not appropriate for all of its activity-level cost benchmarking models. For modelling related to activities, the Authority also used models which were not regression based and did not allow for adjustments through the use of explanatory variables. As such NPg's proposal of an Ofwat type approach is not practicable and the Authority was justified in taking the approach that it did.

223. The Authority also notes that Ofwat's approach was quite different in a further respect, in that it estimated a RLCD for each company, where the Authority only dealt with a RLCD for three regions.

Complaint that in its NIE decision the CC used more granular like-for-like data than the 2-digit SOC codes used by the Authority

224. NPg seeks to rely on the NIE decision, where the CC used 3- and 4-digit SOC code data rather than 2-digit SOC codes.

225. As observed above, there are a small number of approaches which can be taken to set RLCA and the question which approach to adopt is a matter upon

[50] Paragraph 8.21(D), Notice of Appeal

which the relevant regulator must exercise its judgement based on the available evidence. The CC took one approach in the NIE decision, OFWAT another and the Authority a third. The Authority was not bound to follow either of the other two approaches and had cogent reasons for proceeding as it did. The Authority notes that the observations it makes at the start of paragraph 193(f) above as regards the CC's approach in the NIE case in respect of RPEs apply equally here.

226. The approach adopted by the Authority was one which was open to it and was not 'wrong'. The question whether the approach adopted by the CC in its NIE decision was or was not wrong is not relevant to NPg's challenge to the correctness of the Authority's approach.

227. Further or alternatively, the Authority makes the following additional observations:

(a) In the NIE case, the CC disagreed with NIE's assertion that 3-digit SOC codes were "*completely irrelevant*" to NIE and the British DNOs, explaining its method was "*based on data for more aggregated occupational categories than WA1 [4-digit SOC codes] but this does not mean that the data used are irrelevant*"[51].

(b) The CC also noted that averaging over a number of years "help[s] reduce the risks of inaccuracy from a small sample size, but we did not believe that this approach necessarily eliminated those risks."[52]

(c) The use of 4-digit SOC codes risks data being relied upon which is volatile either because of issues relating to the sample size in 4-digit SOC codes or because of year on year volatility.

[51] CC, NIE main report, pages 8-38 -8.39, paragraph 8.214 [**NPg/6/B/23/pages 8-38 to 8-39**]
[52] Ibid, paragraph 8.215.

Complaint that the ONS warned users of its database that the database did not take account of differences in the regional composition of the workforce, so that like for like comparisons may not be appropriate; complaint that alternate sources, such as the Hay Group data or Income Data Services data would have provided a better alternative for this reason

228. The Authority accepts that the data in the ONS database does not take account of differences in regional composition of the workforce.

229. However, in the Authority's view the ONS ASHE dataset is the only independent data in respect of hours and earnings that it would be appropriate to use.

230. NPg suggest the possibility of using alternate sources of data, such as the Hay Group data. In response, the Authority notes that ONS data must meet rigorous statistical standards not always demanded or adhered to by private industry data. There is no reason to conclude that these other alternative sources of data are 'better' and certainly no basis to conclude that reliance on ONS data was 'wrong': that would be a really rather surprising conclusion. Furthermore:

(a) The Hay Group data appears to be a combination of all data received from its clients. Sampling does not appear to be carried out on the data set. Parts of the research methodology are also unclear. By way of example, it is not clear whether the figures include overtime. On the basis that this data is produced in a way which may not lead to objective reporting from Hay's clients and on the basis that there may be a bias in the dataset towards companies which use Hay's services, the Authority takes the view that it is preferable to use objectively obtained data, the categories of which are used can be modified to ensure that only relevant data is used.

(b) The Authority notes that in the NIE case, the CC was, in the context of IDS data, "*concerned that reliance on this type of information could be vulnerable to selection bias".* [**NPg/6/B/23/page 8-38/para 8.210**]

231. In any event, the fact that other potential data *could have been used*, even if such a contention were to be made good, does not begin to show that the Authority was wrong to use the data sources that it did. The Authority was entitled to conclude, in the exercise of its expert judgment, that its selection of data sources was an appropriate one. NPg has failed to demonstrate otherwise.

Complaint that the outcome of the Authority's calculations showed a positive 6% premium for Scotland which the Authority did not reflect in the regions differentiated for the purpose of its assessment

232. The Authority's calculations showed a 6% positive difference for Scotland which it chose, in its expert judgment, not to reflect in the regions differentiated for the purpose of its assessment. In Final Determinations the Authority pointed out "*We do not consider that there is sufficient and compelling new evidence to support applying regional wage differentials for each region of GB given the mobility in the labour market. We maintain our adjustment for three regions. We do not make regional labour adjustments for business support costs in line with our view that these can be procured on a national basis*"[53]

233. As to paragraphs 2.25 and 8.28, for all the reasons set out above, the Authority does not accept that it has made a material underfunding error, that it has failed to have regard or give appropriate weight to its principal objective and duties, that its determination was based on errors of fact or that it acted in error of law in any of the ways alleged. The Authority submits that NPg has failed to identify how the narrow criticisms which it makes of the Authority's overall approach to the assessment of RLCAs relate to the various legal grounds set out in paragraph 2.25.

[53] Final Determinations: Cost assessment [**NPg/1/B/16/page 1126/para. 4.16**].

CONCLUSION

234. For all the reasons given above, the Authority invites the CMA to dismiss NPg's appeal. In the event that the NPg's appeal is allowed in any part, however, the Authority reserves its right to make detailed submissions as to the remedy and licence amendments arising from the CMA's decision.

STATEMENT OF TRUTH

I, Maxine Frerk, on behalf of the Gas and Electricity Markets Authority, believe the facts and information stated in this Response to be true.

Signed:

Maxine Frerk, Senior Partner, Smarter Grids and Governance

Dated: 22/4/15

ANNEX 1

RIIO-ED1 GLOSSARY OF TERMS

A

Administrative burden

Things that business must do or other administrative costs that businesses sustain due to a requirement from regulation. This may include keeping records or responding to information requests.[54]

Allowed revenue

The amount of money that a network company can earn on its regulated business and recover from customers through the distribution use of system charges. Allowed revenue comprises base revenue, incentive rewards or penalties and allowances from uncertainty mechanisms.

Arithmetic mean

A simple average. The sum of all observations divided by the number of observations.

Asset Replacement

An activity undertaken by the DNOs to remove existing assets and install a new asset. The driver for this replacement may be due to poor asset condition, obsolescence or environmental or safety liabilities.

The principal assets replaced as part of a replacement project are captured as primary assets. Where associated assets are also replaced to facilitate the primary asset replacement, these are counted as consequential assets

The Authority/Ofgem/GEMA

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in Great Britain.

Average time to connect incentive

A proposed new price control incentive for RIIO-ED1 that aims to improve the average overall time taken to connect customers to the distribution system.

[54] http://www.berr.gov.uk/whatwedo/bre/policy/simplifying-existing-regulation/administrative-burdens/page44061.html

B

Base revenue

The core amount of money that a network company can earn on its regulated business in order to recover the efficient costs of carrying out its activities. Base revenue includes allowances for operating costs , the return of capital (depreciation), return on capital, tax, pension deficit repair and any adjustments to previous allowances.

Benchmarking

The process used to compare a company's performance (e.g. its costs) to that of best practice or to average levels within the sector.

Better regulation and better regulation principles

Established principles of better regulation state that regulation should be transparent, accountable, proportionate, consistent, and targeted only at cases where action is required.

Ofgem has interpreted better regulation to mean only regulating where necessary whilst designing rules that support competition and protect the customer. As part of our better regulation work Ofgem develops an annual Simplification Plan to help reduce the burden of administration while ensuring consumer protection.[55]

Black Start

The series of actions necessary to restore electricity supplies to customers following a total or widespread partial shutdown of the GB Transmission System. Black Start requires distribution substations to be re-energised and reconnected to each other in a controlled way to re-establish a fully interconnected system.

Black Start Resilience

Refers to resilience of both the distribution network assets and the key telecommunications systems, essential to DNOs for the organisation and coordination of resources, to a prolonged loss of supply in order to implement restoration plans under Black Start conditions. The required level of resilience shall meet the recommendations of the Electricity Task Group sub-committee of the Energy Emergency Executive Committee (E3C).

Bond

A type of debt instrument used by companies and governments to finance their activities. Issuers of bonds usually pay regular cash flow payments (coupons) to bond holders at a pre-specified interest rate and for a fixed period of time.

[55] Further details can be found at the following link: http://www.ofgem.gov.uk/About%20us/BetterReg/Pages/BetterReg.aspx

Broad Measure of Customer Satisfaction (BMCS)

A composite incentive consisting of a customer satisfaction survey, a complaints metric and stakeholder engagement. It was introduced for DPCR5 and is designed to drive improvements in the quality of the overall customer experience by capturing and measuring customers' experiences of contact with their DNO across the range of services and activities the DNOs provide.

Building blocks approach

Building block reviews focus on determining appropriate values for each company's own capital asset values, weighted average cost of capital (WACC), capital expenditures and operating expenditures for the upcoming price control period.

Business Support Costs (BSCs)

The indirect operating costs required to support the overall business. For more information on what this includes, see the Regulatory Instructions and Guidance (RIGs) Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

BT 21st Century (BT21CN)

21CN refers to the roll out of BT‟s next generation communications network which replaces Public Switched Telephone Network (PSTN) with a Digital Internet Protocol (IP). Whilst effectively changing the communications protocol used on the existing network assets, it also accelerates the replacement of copper communications circuits with non-metallic optical fibre.

C

Call Centre

Responding and managing the main telephone lines for the business. Where reports or queries require further investigation by another division of the business these costs are not included except to the extent that a member of the Call Centre team responds after obtaining additional information.

Capital Asset Pricing Model (CAPM)

A theoretical model that describes the relationship between risk and required return of financial securities.

The basic idea behind the CAPM is that investors require a return for the rate of interest, and a return for the level of risk in their investment.

Capital expenditure (capex)

Expenditure on investment in long-lived assets. For more information on what this includes, see the RIGs Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

Capitalisation policy

The approach that the regulator follows in deciding the percentage of total expenditure added to the RAV (and thus remunerated over time) and the percentage of expenditure remunerated in the year it is incurred.

Carbon footprint

Total amount of greenhouse gas emission caused directly and indirectly by a business or activity.

Chief Executive Officer (CEO) and Other Corporate Functions

Combines the activities of:

- Non-executive and group directors labour and Board meeting costs
- Management charges from Affiliates of a general non-specific nature
- Corporate communications/Community Awareness
- Legal services
- Company secretarial services.

For more information on what this includes, see the RIGs Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

CI- Customers interrupted per year

The number of customers interrupted per year (CI). This is the number of customers whose supplies have been interrupted per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident.

CI/CML Schemes

Any discretionary schemes primarily aimed at improving CI and/or CML performance.

Closely Associated Indirect Costs (CAIs)

The indirect operating costs that support the operational activities of the DNO. For more information on what this includes, see the RIGs Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

CML- Duration of interruptions to supply per year

The duration of interruptions to supply per year (CML). This is the average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer.

Competition Commission (CC)

An independent public body which conducts in depth inquiries into mergers, markets and aspects of regulation of the major regulated industries.

Competition and Markets Authority (CMA)

The CMA is a new organisation bringing together the Competition Commission (CC) and the Office of Fair Trading (OFT). The CMA was created in a shadow form by the Enterprise and Regulatory Reform Act 2013 on 1 October 2013 and will take on its full responsibilities from 1 April 2014.

Competition Test

The Competition Test involves an assessment of whether there is effective competition in a relevant market segment. It is set out in Distribution Price Control 5 Final Proposals – Incentives and Obligations and referenced in CRC12.

Composite Scale Variable (CSV)

A method of combining a number of different cost drivers in to a single driver for regression analysis using fixed pre-determined weights.

Connection Boundary

The connection charging boundary describes the split of connection costs between the DNO and the connecting customer. The costs allocated to the connecting customer are recovered via a connection charge and the costs allocated to the DNO will be recovered from all network users via use of system charges.

Connection Quotation

The notice required to be given by an electricity distributor in accordance with section 16A(5) of the Electricity Act 1989.

Connection Completion

The completion of electrical works to the point that, subject only to the fitting of an appropriate meter where necessary, energisation would be possible.

Connections

Within the reporting for DPCR5, the term connection refers to the provision of exit points. All provisions of new exit points or upgrades of existing exit points should be referred to as connections within the annual reporting for connections.

Consumer

In considering consumers in the regulatory framework we consider users of network services (for example generators, shippers) as well as domestic and business end consumers, and their representatives.

Consumer Challenge Group

The consumer challenge group comprises of members appointed by Ofgem on the basis of their expertise in the interests of present and future consumers and energy sector knowledge. Their role in the price control review process is to provide Ofgem with advice on consumer priorities for the price control. To help achieve this the group seeks to identify the main questions that consumers have about the price control and what needs to be addressed in the various documents published by Ofgem in the price review process.

Consumer First Panel

The Panel, set up by Ofgem, consists of 100 domestic customers, recruited from five locations across Great Britain. The Panel meets at least three times a year to discuss key issues related to energy. It was first established in July 2008.

Contestable Activities

Connections activities that can be carried out by a non-affiliated third party with relevant accreditation.

Control Centre

Operational management and control of the network, outage planning and management.
Relates to both the short term and long term outage planning and management that is carried within the Control Centre, at all voltage levels, prior to the undertaking of planned incidents.

Cost of capital

This is the minimum acceptable rate of return on capital investment. It includes both the cost of debt to a firm, and the cost of equity.

Cost of debt

The effective interest rate that a company pays on its current debt. Ofgem calculates the cost of debt on a pre-tax basis.

Cost of equity

The rate of return on investment that is required by a company's shareholders. The return consists both of dividend and capital gains (e.g. increases in the share price). Ofgem calculates the cost of equity on a post-tax basis.

Credit rating

An evaluation of a potential borrower's ability to repay debt. Credit ratings are calculated from financial history and current assets and liabilities. There are three major credit rating agencies (Standard & Poor's, Fitch and Moody's) who use broadly similar credit rating scales, with D being the lowest rating[56] (highest risk) and AAA being the highest rating (negligible risk). The companies regulated by Ofgem typically have a credit rating of BBB, BBB+, A- or A.

Critical National Infrastructure (CNI)

Critical National Infrastructure (CNI) refers to sites designated as CNI by DECC.

Criticality Index (C)

The Criticality Index (C) is a framework for collating information on the Consequences Of Failure of distribution assets and for tracking changes over time.

The Criticality Index is a comparative measure of Consequence Of Failure. For a particular asset, the Criticality Index is provided by:-

- the location of the asset within the Criticality Index Bands; and
- the Average Overall Consequence Of Failure, for the relevant Health Index Asset Category

Customer Contributions

Revenue recovered from specific customer for individual services via relevant charges.

[56] The lowest credit rating on Moody's scale is C.

D

De minimis

Any business conducted or carried on by the licensee, or by an Affiliate or a Related Undertaking of the licensee in which the licensee holds shares or other investments, other than:

- the Distribution Business
- any other business or activity to which the Authority has given its consent under paragraph 4 of standard condition 29 (Restriction of activity and financial ring-fencing of the Distribution Business).

Dead-band

In the context of the tax trigger, the dead-band is a fixed percentage of base demand revenue outside of which, if positive, licensees will receive additional revenues, or, if negative, incur a clawback of base demand revenues that were set at the price control, arising from the activation of the tax trigger and the charge restriction conditions.

Demand connection

A new or modified connection that enables the premise to receive a supply of electricity from the electricity distribution system.

Demand side management (DSM)

Demand side management (or load management) is any mechanism (both social and mechanical) that allows a customer's demand to be intelligently managed in response to events on the power system. Such events would include lack of network capacity or insufficient generation.

Department of Energy and Climate Change (DECC)

Depreciation

Depreciation is a measure of the consumption, use or wearing out of an asset over the period of its economic life.

Direct Activities

Those activities which involve physical contact with system assets. For more information on what this includes, see the RIGs Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

Direct Expenditure

Expenditure incurred undertaking Direct Activities.

Design Life

The period over which an asset is designed to last.

Dismantlement

Dismantlement is the activity of de-energising, disconnecting and removing (where appropriate) network assets where the cost of dismantlement is not chargeable to a third party and no new assets are to be installed.

Distributed Generation (DG)

Any generation which is connected to the local distribution network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported across the UK.

Means an installation comprising any plant or apparatus for the production of electricity that is directly connected to the licensee"s Distribution System or is connected to that system through one or more electricity networks (other than an onshore Transmission System) that is or are directly connected to it.

Distributed Generation (DG) Forum

A series of regional events held by Ofgem in 2011 and 2012 to discuss explore the experience of connecting distribution generation to the distribution network.

Distributed Generation (DG) Information Strategy

A strategy set out by the distribution network operator and approved by the Authority that outlines how the distribution network operator intends to ensure that all existing and potential DG connection customers of its distribution system are able to receive an adequate level of information and a satisfaction standard of service.

Distributed Generation (DG) Connections Guide

A common set of documents produced by the DNOs and approved by the Authority that provides guidance on:

- The details of the statutory and regulatory framework (including health and safety considerations) that apply to DG connections
- The likely costs, charges, and timescales involved in the application process.
- The details of the arrangements and opportunities available for competitive activity in the provision or procurement of a connection.

- Engineering and other technical matters relevant to the commissioning, energisation, and maintenance of such connections.

Distribution billing (DUoS)

For the purposes of the IT and Telecoms Systems Overview worksheet of the Cost and Revenue RIGs, are IT systems that assist with DUoS billing.

Distribution Network Operators (DNOs)

Holders of electricity distribution licences. Licences are granted for specified geographical areas in Great Britain. Currently there are 14 DNOs owned by six different groups.

Distribution Price Control Review 3 (DPCR3)

The price control review for the electricity distribution network operators covering the period from 1 April 2000 to 31 March 2005.

Distribution Price Control Review 4 (DPCR4)

The price control review for the electricity distribution network operators covering the period from 1 April 2005 to 31 March 2010.

Distribution Price Control Review 5 (DPCR5)

The price control review for the electricity distribution network operators covering the period from 1 April 2010 to 31 March 2015.

Distribution network

The distribution system is a network of wires, transporting electricity from the transmission system or distribution connected generation to domestic, commercial and industrial electricity consumers.

The electricity distribution network includes all parts of the network from 132kV down to 230V in England and Wales. In Scotland 132kV is considered to be a part of transmission rather than distribution.

Diversions (conversion of wayleaves to easement)

Costs involved in retaining assets by way of the purchase of land or easements and the cancellation of terminable agreements, for example in response to injurious affection claims.

Diversions (non-fully rechargeable)

Diversions activity that is not fully recharged to any third party or agent.

Diversions due to wayleave terminations

The raising or rerouting of a circuit and/or the relocation of plant following the termination of a wayleave or lease.

Diversions for Highways

The raising or rerouting of a circuit or repositioning of plant associated with new roads or streetworks. Such costs represent the DNO proportion of the costs. The proportion that is charged to the customer is reported under ES2.

Draft Determinations

Consult on the proposed DNO settlements for the price control period. In previous price control reviews, Draft Determinations were called Initial Proposals.

E

Early Retirement Deficiency Contributions (ERDC)

Cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.

Earthing upgrades

Where earthing, at a substation site with a primary voltage greater than HV, has been upgraded by the installation of additional earth electrodes to mitigate against a high earth potential rise (EPR) or step and touch potentials in excess of tolerable limits.
This excludes sites where earthing has been replaced due to fault or theft.

Easements

An entitlement to retain assets in a location for a determined period of time or in perpetuity without risk of interference from the owner.

Economic Life

The period over which an asset performs a useful function.

EHV (Extra High Voltage)

Voltages over 20kV up to, but not including, 132kV.

EHV end connection involving only EHV work

A demand connection at EHV level where the only voltage of the assets involved in providing such connection, and any associated works, is EHV.

Energisation

The insertion of a fuse or operation of a switch that will allow an electrical current to flow from an electricity distributor's distribution system to the customer's installation, or from the customer's installation to that distribution system.

Energy Ombudsman/Ombudsman Services (EO)

Ombudsman Services provides an independent dispute resolution service for the communications, energy, property and copyright licensing sectors.

Engineering Management and Clerical Support

The office-based activities of engineering and clerical support staff (i.e. depot clerical staff, managers, work planners, etc) managing or assisting employees undertaking direct activities and wayleave administration.

Equity beta

The equity beta measures the covariance of the returns on a stock with the market return. The weaker this co-variance, the greater the contribution that the stock could make to reducing the exposure to systematic risk, and hence the lower the return that investors would require on that stock.

Equity risk premium

A measure of the expected return, on top of the risk-free rate, that an investor would expect for a portfolio of risk-bearing assets. This captures the non-diversifiable risk that is inherent to the market. Sometimes also referred to as the 'market risk premium'.

Excluded Market Segment

Any of the excluded market segments that are described in or determined in accordance with Appendix 1 of Charge Restriction Condition 12 (CRC 12). In DPCR5 Final Porposals Ofgem considered that competition was not viable in these market segments at that time or in the foreseeable future.

F

Fault

Any incident arising on the licensee's distribution system, where statutory notification has not been given to all customers affected at least 48 hours before the commencement of the earliest interruption (or such notice period of less than 48 hours where this has been agreed with the customer(s) involved).

Fault Level Reinforcement

Work carried out on the existing network where the prime objective is to alleviate fault level issues associated with switchgear or other equipment.

Fault Rate

A Fault Rate is the incidence per unit of unplanned incidents for a specific category of distribution assets.

Fault Rates form part of the DPCR5 Network Output Measures.

Final Determinations

Set out the final DNO settlements for the price control period. In previous price control reviews, Final Determinations were called Final Proposals.

Finance and Regulation

Performing the statutory, regulatory and internal management cost and performance reporting requirements, and customary financial and regulatory compliance activities for the DNO.

Financeability

Financial models are used to determine whether the regulated energy network is capable of financing its necessary activities and earning a return on its regulated asset value (RAV) under the proposed price control. This financeability is assessed using a range of different financial ratios.

Financial structure

The way in which a company finances its assets, for example through short-term borrowings, long-term debt and shareholder equity.

Fuel poverty

A fuel poor household is defined as one that needs to spend 10% or more of their household income on all fuel use in order to maintain a satisfactory heating regime. DECC's latest fuel Fuel Poverty review (Hills Fuel Poverty Review) recommends that any household that requires fuel costs above the median level and, if they were to spend that, are left below the official poverty line, should be defined as fuel poor.

G

Gas and Electricity Markets Authority (GEMA)

(See the Authority/Ofgem)

Gearing

A ratio measuring the extent to which a company is financed through borrowing. Ofgem calculates gearing as the percentage of net debt relative to the Regulatory Asset Value (RAV).

General Reinforcement

Work carried out on the network in order to enable new load growth (both demand and generation) which is not attributable to specific customers.

General reinforcement (EHV & 132kV N-1)

Work carried out on the network required to maintain or restore compliance with ER P2/6 or avert future non-compliance for first circuit outages.

General reinforcement (EHV & 132kV N-2)

Work carried out on the network required to maintain or restore compliance with ER P2/6 or avert future non-compliance for second circuit outages (a fault outage following an arranged outage).

General reinforcement (EHV & 132kV Other)

Work carried out on the network which falls outside of General Reinforcement (EHV and 132kV N-1) and General Reinforcement (EHV and 132kV N-2) such as:

- Reinforcement to correct potential voltage non-compliance
- Reinforcement to correct issues at a lower voltage where it is the most efficient and economic solution.

It excludes work associated with High Impact, Low Probability (HILP) expenditure.

Generation connection

A new or modified connection that enables the electricity distribution system to receive a supply of electricity from the premises.

Geometric Mean

A measure of the average value of a set of numbers, sometimes viewed as a better measure of the true average than the arithmetic mean it is calculated as the nth root (where n is the number of observations) of the product of all observations.

Gigawatt Hour (GWh)

Equal to one million Kilowatt Hours.

Greenhouse gas (GHG)

A collection of gases which absorb infrared radiation and trap its heat in the atmosphere.

Guaranteed Standards of Performance

A set of service levels that must be met by each distribution company. These standards have been set to guarantee a level of performance that is reasonable to expect companies to deliver in all cases.

If the distribution company fails to meet the level of performance required, it must make a payment to the customer subject to certain conditions.

There are two sets of Guaranteed Standards of Performance, one for connections and one for reliability.

Payments under the guaranteed standards compensate for the inconvenience caused. They are not designed to compensate customers for subsequent financial loss.

H

Health Index (HI)

The Health Index (HI) is a framework for collating information on the health (or condition) of Distribution Assets and for tracking changes in their condition over time. The HI will be used to inform an assessment of the efficacy of the DNOs' asset management decisions over the price control period. Under the HI framework, each relevant asset is assigned a ranking by the DNO based on the DNO‟s assessment of its overall health or condition, and for the forecast period based on the DNO‟s views about future degradation, the options for Intervention and their impacts.

Health index arrangements were introduced as a part of DPCR5. Also see Network Output Measures.

The Health and Safety Executive (HSE)

A public body responsible for regulating health and safety in Great Britain with the primary function to secure the health, safety and welfare of people at work and to protect others from risks to health and safety from work activity.

Health and Safety and Operational Training

Health and Safety is the activity of promoting and maintaining health and safety of employees, contractors, customers and the public.

High Impact Low Probability (HILP)

These are extreme events that could result in the prolonged loss of supply to localities that have a high gross [economic] value added (GVA). HILP activity relates to increasing the security of supply, to localities that have a high GVA, to levels that exceeds P2/6 recommended levels.

High Value Projects (HVPs)

Schemes specified and agreed with individual DNOs to be undertaken during the DPCR5 period as laid out by Ofgem in the DPCR5 Final Proposals document.

HV (High Voltage)

Voltages over 1kV up to, but not including, 22kV.

HV end connections involving EHV work

A demand connection at HV level where the highest voltage of the assets involved in providing such connection, and any associated works, is extra high voltage.

HV end connections involving only HV work

A demand connection at HV level where the only voltage of the assets involved in providing such connection, and any associated works, is high voltage.

HV network

The DNO network that operates at all voltages above 1kV up to and including 20kV.

HV or EHV end connections involving 132kV work

A demand connection provided at either HV or EHV, where the highest voltage of the assets involved in providing such connection, and any associated works, is 132kV.

Human Resources and Non-Operational Training

The personnel management of all staff, and the provision of non-engineering training to office-based staff.

I

IDNO (Independent Distribution Network Operator)

Any Electricity Distributor in whose Electricity Distribution Licence the requirements of Section B of the standard conditions of that licence have no effect (whether in whole or in part).

Incentive rate (efficiency)

The percentage of underspends/overspends against expenditure allowed at the price control review that is kept by the company responsible. The remaining savings/losses are passed through to consumers.

Independent Connection Providers (ICPs)

An independent connections provider not affiliated to a distribution network operator.

Indexation

The adjustment of an economic variable so that the variable rises or falls in accordance with the rate of inflation.

Incident

An incident is defined as any occurrence on the DNO"s Distribution System or other connected distributed generation, transmission or Distribution System, which:

- results in an interruption of supply to customer(s) for three minutes or longer, or
- prevents a circuit or item of equipment from carrying normal load current or being able to withstand “through fault current” for three minutes or longer.

Indirect Activities

Those activities which do not involve physical contact with system assets. For more information on what this includes, see the RIGs Glossary: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/DPCR5_Glossary_of_Terms_clean[1].pdf

Indirect Costs

The costs incurred undertaking Indirect Activities.

Inflation index

This is a measure of the changes in given price levels over time. A common example is the Retail Prices Index (RPI), which measures the aggregate change in consumer prices over time.

Inspections and Maintenance

Is the overall activity that encompasses Inspections, Shrouding of LV overhead line conductors and Repairs & Maintenance.

This excludes site surveys in relation to areas at risk of flooding.

Interconnector

Equipment used to link electricity systems, in particular between two Member States.

Interruption

An interruption is defined as the loss of supply of electricity to one or more customers due to an incident but excluding voltage quality and frequency abnormalities, such as dips, spikes or harmonics.

Interruptions Incentive Scheme (IIS)

Scheme which provides financial incentives to DNOs with respect to the average quality of service they provide in terms of:

- the number of interruptions to supply (measured in CI)
- the duration of interruptions to supply (measured in CML)

IT and Telecoms (IT&T)

The purchase, development, installation, and maintenance of non-operational computer and telecommunications systems and applications.

K

Key Performance Indicator (KPI)

A set of benchmarks to be met by DNOs; they are not backed up with any specific licence conditions or financial incentives.

Kilowatt Hours (KWh)

A unit of energy equal to the work done by a power of 1000 watts operating for one hour.

L

Large User Group (LUG)

A key forum for engaging with business customer representatives. The LUG is open to large sized users of energy, for example metal manufacturers such as Corus.

Legal and Safety

Investment or intervention where the prime driver is to meet safety requirements and to protect staff and the public. This does not include assets replaced because of condition assessment or to meet ESQCR regulations 17 and 18.

Licence conditions (obligations)

An obligation placed on the network companies to meet certain standards of performance. The Authority (GEMA) has the power to take appropriate enforcement action in the case of a failure to meet these obligations.

Load Index (LI)

The Load Index (LI) is a framework for collating information on the utilisation of individual substations or groups of interconnected substations and for tracking changes in their utilisation over time.

The LI will be used to inform an assessment of the efficacy of the DNOs' general reinforcement decisions over the price control period. Under the LI framework, each Demand Group is assigned a ranking based on the loading and firm capacity at the site, and for the forecast period based on the DNO's views about future load growth, the options for Intervention and their impacts.

The Load Index was introduced as a part of DPCR5. Also see Network Output Measures

Load Related Capex

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

Load Related Expenditure (LRE)

LRE refers to expenditure relating to the following activities:

- Connections
- Diversions and Wayleaves/Easements
- General Reinforcement
- Fault Level Reinforcement
- Relevant High Value Projects (HVPs).

Logging up

A type of uncertainty mechanisms, logging up is a provision that a company will be compensated for all, or part, of its actual expenditure on a particular activity or area, through the revenue allowance set at the next price control review.

Long Term Development Statement

A document that sets out the use and likely development of the distribution network and the distribution network operator's plans for modifying the distribution system for the following two years. The document should also cover the parts of the distribution system that are likely to reach capacity during the next five years, the distribution network operator's plans to reduce any shortcomings in operation/capacity and (where applicable) how actual developments have compared to the distribution network operator's plans under the previous statements. All distribution network operators must produce and maintain a LTDS.

Losses

Is defined in the electricity distribution licence as the difference between units entering and units exiting the DNO network through different connection points.

Low carbon economy

An economy which has a minimal output of greenhouse gas emissions.

Low Carbon Networks Fund (LCN Fund)

A mechanism introduced under the fifth distribution price control review to encourage the DNOs to use the forthcoming price control period to prepare for the role they will have to play as GB moves to a low carbon economy. The fund will see up to £500m made available for DNOs and partners to innovate and trial new technologies, commercial arrangements and ways of operating their networks.

Lower Quartile (LQ) Cost Benchmarking

For the purposes of this document LQ cost benchmarking refers to the approach of setting the benchmark at the 75th percentile (ie the highest) of DNOs' costs. This approach has typically been proposed for areas of expenditure where there is a high degree of variability across different DNOs' expenditure.

See also Upper Quartile Cost Benchmarking

LV (Low Voltage)

This refers to voltages up to, but not including, 1kV.

LV end connections involving EHV work

A demand connection provided at LV where the highest voltage of the assets involved in providing such connection, and any associated works, is EHV.

LV end connections involving HV work

A demand connection provided at LV where the highest voltage of the assets involved in providing such connection, and any associated works, is HV.

M

Market-to-Asset Ratio (MAR)

The ratio between a company's market value and its Regulatory Asset Value (RAV). This can be estimated from transactions (eg sale of a network) or, for companies listed in the stock market, from market capitalisation data. An MAR value greater than one might indicate that investors value a company above its RAV.

Metered Connection

A connection that has a meter to measure consumption of electricity

Modern Equivalent Asset (MEA)

This is the current replacement value of an asset.

N

National Grid Electricity Transmission (NGET)

The electricity transmission licensee in England & Wales.

National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Net Present Value (NPV)

NPV is the discounted sum of future cash flows, whether positive or negative, minus any initial investment.

Network charges

These are charges set for the use of network services.

Network Design and Engineering

All processes and tasks involved in the:

- Strategic planning of the distribution network at all voltages; and

- Detailed engineering design of new connections, extensions and changes to the distribution network at all voltages.

Network Innovation Allowance (NIA)

A set, use-it-or-lose-it allowance, that each DNO will receive in order to fund small-scale innovative projects as part of their price control settlement. The value of the NIA will be between 0.5 and 1 per cent of base revenues.

Network Innovation Competition (NIC)

A single annual competition for electricity transmission and distribution network companies to apply for funding to trial large-scale, innovative projects with low carbon or other environmental benefits. Companies can apply to have a maximum of 90 per cent of the project costs funded through the NIC.

Network Investment

Includes all costs associated with the following activities:

- Metered demand connections (Use of System funded)
- Core Network Investment
- Non-Core (ex-ante)
- Nore Core (reopener/logging up)
- Standalone funding (RAV)
- Standalone funding (not RAV)
- High Value Projects (HVPs).

Network Operating Costs (NOCs)

Collectively includes the activities of:

- Trouble Call
- Atypicals – Severe Weather one-in-twenty Events
- Inspections and Maintenance
- Tree Cutting
- NOCs Other

Network Output Measures

The Network Output Measures were introduced in DPCR5 and consisted of the Health Index, Load Index and Fault Rates. This framework ties the DNOs in to the

delivery of specified network improvements by linking activities to allowed revenues. The arrangements are comparable to RIIO Secondary Deliverables.

Network Policy

The development and review of environmental, technical and engineering policies, including all research and development apart from any defined as IFI.

It includes evaluating the impact of changes in relevant legislation; and development, regular review and updating of engineering policies.

Network users

Companies along the gas and electricity supply chain (i.e. producers/generators, transmission and distribution networks, and energy suppliers).

Non-contestable activities

Connection activities that cannot be carried out by a non-affiliated third party with relevant accreditation.

Non-Load Related Capex

The replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

Non Load Related Expenditure (NLRE)

The installation of new assets and the planned installation of replacement assets for reasons other than load-related reasons.

Non Quality of Service Occurrences

Any occurrence logged on the enquiry service operated by the licensee under standard condition 8 (Safety and Security of Supplies Enquiry Service) which is not an incident.

Non-Operational Capex

Expenditure on new and replacement assets which are not system assets.

O

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overhead.

Operational Information Technology and Telecoms (IT&T)

IT equipment which is used exclusively in the real time management of network assets, but which does not form part of those network assets.

Operational training

Includes the activities of:

- Classroom training and
- On the job training
- Trainer and course material costs (classroom training)
- Training centre building & grounds and training admin
- Recruitment - operational training

For the following purposes

- Training Workforce renewal new recruit
- Operational upskilling.
- Operational refresher training

Outcomes (objectives of new regulatory framework)

What the network companies are expected to deliver. The outcomes that we expect from the new framework are that network companies play a full role in the delivery of a sustainable energy sector and deliver value for money network services for existing and future consumers.

Outputs

Output information is to be used to assess network company performance against the outcomes within a control period. This information may be both qualitative and quantitative in nature.

P

Pass through (of costs)

Costs for which companies can vary their annual revenue in line with the actual cost, either because they are outside the DNO‟s control or because they have been subject to separate price control measures.

Pension protection fund (PPF)

The Pension Protection Fund was established to pay compensation to members of eligible
defined benefit pension schemes, when there is a qualifying insolvency event in relation

to the employer and where there are insufficient assets in the pension scheme to cover
Pension Protection Fund levels of compensation.

Post Maintenance Interest Cover Ratio (PMICR)

A financial ratio used by rating agencies when determining credit ratings. It measures the amount of cash a company generates from the revenues it brings in, excluding costs associated with long-term investment (capex) relative to the interest paid on the company's debt.

Price control (control)

The control developed by the regulator to set targets and allowed revenues for network companies. The characteristics and mechanisms of this price control are developed by the regulator in the price control review period depending on network company performance over the last control period and predicted expenditure in the next.

Priority Service Register

A register of all customers in an electricity distribution area that are of pensionable age, disabled, chronically sick, require special communication needs, depend on electricity for medical reasons, or require certain information and advice about supply interruptions. The electricity distribution network operator must provide all customers on their PSR with prior advice and information about planned interruptions and appropriate information and advice about what precautions to take in the event of an unplanned supply interruption.

Profile classes

Profile classes are used to differentiate between customer types. This differentiation is based on the when customers consume electricity across the day. A profile is made of up of estimated consumption in each half hour across a 24 hour period based on generic customer characteristics and the tariff which a customer is on. For instance, a domestic customer is more likely to have higher consumption on weekday mornings and evenings and lower during the day time. A non domestic customer is likely to have higher consumption in the daytime but lower (or none at all) in the morning and evening.

The eight generic profile classes were chosen by industry as they represented large populations of similar customers. The eight profile classes are as follows:

- Profile Class 1 Domestic Unrestricted Customers
- Profile Class 2 Domestic Economy 7 Customers
- Profile Class 3 Non-Domestic Unrestricted Customers
- Profile Class 4 Non-Domestic Economy 7 Customers
- Profile Class 5 Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20%

- Profile Class 6 Non-Domestic Maximum Demand Customers with a Peak
  Load Factor between 20% and 30%
- Profile Class 7 Non-Domestic Maximum Demand Customers with a Peak
  Load Factor between 30% and 40%
- Profile Class 8 Non-Domestic Maximum Demand Customers with a Peak
  Load Factor over 40%

A Peak Load Factor is the ratio, expressed as a percentage, of the number of kWh supplied during a given period compared to the number of kWh that would be supplied at times of maximum demand.

The profile classes are monitored and updated if consumption patterns amongst customers change. They are used by all industry parties to help estimate consumption at certain times.

Project Management

Project management costs from authorisation through preparation, construction and energisation to completion.

Property Management

The costs of providing, managing and maintaining all non-operational premises (with the exception of operational training centres).

Q

Quality of Service (QoS) costs

Costs where the prime purpose is to improve performance against the IIS targets or to improve the overall fault rate per km of the distribution network.

R

Real Price Effects (RPE)

Expected changes in input prices, eg wages, relative to the Retail Price Index (RPI).

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution or (as the case may be) transmission business (the 'regulated asset base').

The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts

calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock.

Regulatory burden

A term used to describe the cost – both monetary and opportunity – of regulation.

Regulatory Instructions and Guidance (RIGs)

A document that is published as part of the price control settlement which sets out further detail on how the price control is to be implemented and how compliance with it will be monitored.

Relevant Market Segments

Any of the relevant market segments that are described in or determined in accordance with Appendix 1 of Charge Restriction Condition 12 (CRC 12). In DPCR5 Final Proposals Ofgem considered that competition is viable in these market segments. DNOs currently charge a four per cent margin on contestable services provided in these market segments.

Remote Location Generation

Remote location generation relates to the cost of fuel and contribution to maintenance to run and test diesel generation that provides permanent emergency backup in remote locations including islands.

Re-openers

A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances) under a price control before the scheduled next formal review date for the relevant price control.

Retail Prices Index (RPI)

The RPI is an aggregate measure of changes in the cost of living in the UK. It differs from the CPI in that measures changes in housing costs and mortgage interest repayments, whereas the CPI does not, they are calculated using different formulae and have a number of other more subtle differences.

Return on Regulatory Equity (RORE)

The financial return achieved by shareholders in a licensee during a price control period from its out-turn performance under the price control. The return is measured using income and cost definitions contained in the price control regime (as opposed to accounting conventions) and is expressed as a percentage of (share) equity in the business. Importantly, in the calculation the gearing (proportions of share equity and

debt financing in the RAV) and cost of debt figures used are those given as the 'assumed' levels in the relevant price control final proposals. The aim of the RoRE measure is to provide an indication of the return achieved by the owners of a licensee which can be compared to the cost of equity originally allowed in the price control settlement and to the return achieved by other licensees on an equivalent basis.

Revenue driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

RIIO (Revenue = Incentives + Innovation + Outputs)

Ofgem's new regulatory framework, stemming from the conclusions of the RPI-X@20 project, to be implemented in forthcoming price controls. It builds on the success of the previous RPI-X regime, but better meets the investment and innovation challenge by placing much more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network at value for money to existing and future consumers

RIIO-ED1

The price control review for the electricity distribution network operators, following DPCR5. This price control will run from 1 April 2015 to 31 March 2023.

RIIO-GD1

The price control review for the gas distribution network operators, following GDPCR. This price control runs from 1 April 2013 to 31 March 2021.

RIIO-T1

The price control review for the electricity and gas transmission network operators, following the TPCR4 rollover. This price control runs from 1 April 2013 to 31 March 2021.

Rising and Lateral Mains

Individual DNO owned 3 phase cable or busbar, not laid in the ground, which runs within or attached to the outside of a multiple occupancy building for:

- More than 3m vertically or
- More than 3m horizontally
- And to which a number of individual services are connected, usually via a distribution board.

Risk-free rate

The rate of return that an investor would expect to earn on a "riskless" asset. Typically, government-issued securities are considered the best available indicator of the risk-free rate due to the extremely low likelihood of the government defaulting on its obligations.

Rolling average

An average of a specified number of data points which is updated continuously to reflect the most recent data.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will reduce by 'X' per cent in real terms.

RPI-X@20

Ofgem's comprehensive review of how we regulate energy network companies, announced in March 2008. Its conclusions published in October 2010 resulted in the implementation of a new regulatory framework, known as the RIIO model.

S

Secondary deliverables

Indicators of performance which may be used in support of the companies' required primary outputs

Settlement data

Data arising through the Balancing and Settlement Code (BSC) settlement processes.

Severe weather 1-in-20 events

Events which gives rise to more than 42 times the mean incidents at HV and above, give rise to more than the threshold for customer interruptions or customer minutes lost.

Small and Medium User Group (SMUG)

A key forum for engaging with business customer representatives. The SMUG is open to small and medium sized users of energy, for example consumer groups such as the Federation of Small Businesses or the British Chambers of Commerce.

Small tools & equipment (& other non-op Capex)

Expenditure on new and replacement Small Tools & Equipment assets which are not system assets.

Smart grid

An electricity network that can intelligently integrate the actions of all the users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies.

Span

Relates to overhead lines and is the term used to describe the portion of overhead line between two overhead line supports (i.e. poles and towers). The number of spans associated with a double circuit line

Spans Cut

Relates to overhead line spans that are inspected in a reporting year in order to assess the need to undertake tree cutting to meet the requirements of ENATS 43-8 and where tree cutting is undertaken during the reporting year.

Spans Inspected (but not cut)

Relates to overhead line spans that are inspected in a reporting year in order to assess the need to undertake tree cutting to meet the requirements of ENATS 43-8 and where no tree cutting is undertaken during the reporting year.

Spans Managed

Is the sum of "Spans Cut" and "Spans Inspected (but not cut)"

Stakeholder

Stakeholders are those parties that are affected by, or represent those affected by, decisions made by network companies and Ofgem. As well as consumers, this would for example include Government and environmental groups.

Storage

Storage refers to any mechanism which can store energy which has been converted into electricity. This can be primary (super-conducting and capacitor technologies); mechanical (pumped hydro, compressed air, flywheels); and electrochemical (batteries).

Stores

The activity of managing and operating stores

Includes:

- Delivery costs of materials or stock to stores
- Labour and transport costs for the delivery of materials or stock from a centralised store to a satellite store (and vice versa)
- Quality testing of materials held in stores
- The value of losses on materials held in stores
- The costs of membership of the “ngt spares club".

Excludes:

- Costs of oil or other insulation medium (report under the activity for which it is used, e.g. Maintenance, faults)
- IT and property costs associated with Stores.

Straight line depreciation

Straight line depreciation depreciates the asset value in a linear fashion throughout its useful life. It is calculated by dividing the Gross Book Value of an asset by its expected useful life.

Sulphur Hexafluoride (SF_6)

A potent greenhouse gas frequently used in electrical equipment.

SF6 Leakage

Electrical plant utilising SF6 for insulation purposes containing the gas in a gas tight enclosure. Loss of integrity of the enclosure leads to escape or leakage of the gas.

Supply chain

Refers to all the actors involved in the delivery of electricity and gas to the final consumers - from electricity generators and gas shippers, through to electricity and gas suppliers.

Sustainable development

Refers to economic development which meets the needs of the present without compromising the ability of future generations to meet their own needs.

Sustainable energy sector

A sustainable energy sector is one which promotes security of supply over time; delivers a low carbon economy and associated environmental targets; and delivers related social objectives (e.g. fuel poverty targets).

System Mapping

The activity of mapping of the network and operational premises of the network to geographical locations.

System Operator (SO)

NGG as the gas system operator has responsibility to construct, maintain and operate the NTS and associated equipment in an economic, efficient and co-ordinated manner. NGET as the electricity system operator has responsibility to construct, maintain and operate the NETS and associated equipment in an economic, efficient and co-ordinated manner. In their roles as SOs, NGG and NGET are responsible for ensuring the day-to-day operation of the transmission systems.

T

Technical Life

The estimated length of time from the date of commission to a point in time when on average the assets fall below minimum acceptable and / or safety performance levels.

Terawatt (TWh)

Equals one thousand Gigawatt hours.

Third Package (Third Internal Energy Market Legislative Package)

The third package is a key step in implementation of internal EU energy market. It recognises the need for better co-ordination between European network operators and continuing co-ordination between regulators at that level. It continues many of the internal market principles identified above in relation to the earlier First and Second Packages.

Traffic Management Act (TMA)

Introduced in 2004 to tackle congestion and disruption on the road network. The TMA Act places a duty on local traffic authorities to ensure the expeditious movement of traffic on their road network and those networks of surrounding authorities. It gives authorities additional tools to better manage parking policies, moving traffic enforcement and the coordination of street works

Total expenditure (Totex)

Totex generally consists of all the expenditure relating to a licensees regulated activities but with the exception of some specified expenditure items. The annual net additions to RAV are calculated as a percentage of the totex.

Total capital expenditure (capex) plus operational expenditure (opex). It can be seen as the aggregate net network investment, net network operating costs and indirect costs, less the cash proceeds of sale of assets and scrap.

Transmission Owners (TO)

Companies which hold transmission owner licenses. Currently there are three electricity TOs; NGET, SPTL and SHETL. NGG NTS is the gas TO.

Transmission system

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

Transmission System Operator (TSO)

See System Operator

Tree Cutting

The activity of physically felling or trimming vegetation from around network assets.

Trouble Call

The activity relating the resolution of Trouble Call occurrences.

U

Uncertainty mechanisms

Uncertainty mechanisms allow changes to the base revenue during the price control period to reflect significant cost changes that are expected to be outside the company's control. Examples include revenue triggers and volume drivers.

Undergrounding

Is the process of replacing overhead power cables with buried electricity distribution cables.

Unmetered Connection

A connection where the charges for electricity consumption are not measured via a meter. The Electricity (Unmetered) Supply Regulations 2001 describe the circumstances in which a supply of electricity may be unmetered, for example small electricity loads that have predictable consumption.

Upper Quartile (UQ) Cost Benchmarking

For the purposes of this document UQ cost benchmarking refers to the approach of setting a benchmark at the 25th percentile (ie the lowest) of DNO costs. This

approach has typically been proposed for areas of expenditure where there is a high degree of commonality across different DNOs' expenditure.

See also Lower Quartile Cost Benchmarking

V

Vanilla Weighted Average Cost of Capital (Vanilla WACC)

The weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity.

Vehicles and transport costs

The activity of managing, operating and maintaining the commercial vehicle fleet and mobile plant utilised by the DNO or any other related party for the purposes of providing services to the DNO.

Vertically integrated company

A company that is active at more than one level of an industry's supply chain (e.g. a company that generates electricity and also operates electricity distribution networks).

VIX index

Chicago Board Options Exchange Volatility Index, a popular measure of implied volatility
with high values implying pessimism and low values implying optimism.

W

Wayleaves

Access to property granted by a landowner including provision for constructing, retaining, using and maintaining an overhead line or underground cable

Wayleaves and Easements/Servitudes Admin Costs

Obtaining, managing and administering Wayleave, substation rents, easements and servitudes.

Wayleaves Payments

Annual payments made in advance to the owner and/or occupier to cover the financial impact of having equipment on their land

Weighted Average Cost of Capital (WACC)

The weighted average of the cost of equity and the cost of debt, where the weighting is provided by the gearing ratio. This represents the cost to a company of raising the funds for its activities (specifically, its capex programme). As part of the price control process, Ofgem sets an allowance for the expected WACC that its regulated companies pay.

Workforce Renewal

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.

ANNEX 2

CHRONOLOGY OF RIIO-ED1

Date	Event
2008-2010	GEMA undertakes its "RPI-X@20" review publishing consultations, responses, and working papers as part of its review of the regulatory regime for energy networks.
4 October 2010	GEMA issues its final decision on the RIIO model for energy network regulation – a product of the RPI-X@20 review.
6 February 2012	GEMA launches open letter consultation on the way forward for the new electricity distribution price control review – RIIO-ED1.
29 February 2012	Flexibility and Capacity Working Group
12 April 2012	Reliability and Safety Working Group
16 April 2012	Flexibility and Capacity Working Group
26 April 2012	Cost Assessment Working Group
27 April 2012	Connections Working Group
3 May 2012	Reliability and Safety Working Group
4 May 2012	Losses Working Group
9 May 2012	Flexibility and Capacity Working Group
10 May 2012	Cost Assessment Working Group
16 May 2012	Environment Working Group
17 May 2012	Reliability and Safety Working Group
24 May 2012	Connections Working Group
28 May 2012	Losses Working Group
29 May 2012	Cost Assessment Working Group
30 May 2012	Flexibility and Capacity Working Group
31 May 2012	Reliability and Safety Working Group
14 June 2012	Reliability and Safety Working Group
19 June 2012	Customer and Social Issues Working Group
20 June 2012	Flexibility and Capacity Working Group
21 June 2012	Environment Working Group
21 June 2012	Connections Working Group
22 June 2012	Losses Working Group
26 June 2012	Cost Assessment Working Group
28 June 2012	Reliability and Safety Working Group
10 July 2012	Cost Assessment Working Group
11 July 2012	Flexibility and Capacity Working Group
12 July 2012	Reliability and Safety Working Group
13 July 2012	Business Plan Guidance Workshop
18 July 2012	Losses Working Group

Date	Event
24 July 2012	Reliability and Safety Working Group
24 July 2012	Customer and Social Issues Working Group
31 July 2012	Cost Assessment Working Group
31 July 2012	Connections Working Group
1 August 2012	Flexibility and Capacity Working Group
8 August 2012	Reliability and Safety Working Group
29 August 2012	Connections Working Group
17 September 2012	Data Assurance Working Group
18 September 2012	Cost Assessment Working Group
28 September 2012	GEMA publishes its strategy consultation for RIIO-ED1.
9 October 2012	Cost Assessment Working Group
19 October 2012	Flexibility and Capacity Working Group
23 October 2012	Customer and Social Issues Working Group
24 October 2012	Connections Working Group
25 October 2012	Reliability and Safety Working Group
5 November 2012	Reliability and Safety Working Group
13 November 2012	Cost Assessment Working Group
19 November 2012	Flexibility and Capacity Working Group
26 November 2012	Data Assurance Working Group
4 December 2012	Cost Assessment Working Group
11 December 2012	Connections Working Group
13 December 2012	Cost Assessment Working Group
14 December 2012	Customer and Social Issues Working Group
19 December 2012	Flexibility and Capacity Working Group
19 December 2012	Reliability and Safety Working Group
20 December 2012	Losses Working Group
16 January 2013	Connections Working Group
16 January 2013	Customer and Social Issues Working Group
17 January 2013	Cost Assessment Working Group
19 January 2013	Flexibility and Capacity Working Group
24 January 2013	Reliability and Safety Working Group
21 February 2013	Customer and Social Issues Working Group
21 February 2013	Connections Working Group
22 February 2013	Flexibility and Capacity Working Group
4 March 2013	GEMA published its decision on its approach to RIIO-ED1 – the strategy decision.
26 March 2013	Cost Assessment Working Group
26 March 2013	Customer and Social Issues Working Group
26 March 2013	Connections Working Group
June 2013	The DNOs submit their fast-track business plans to GEMA.
5 June 2013	Customer and Social Issues Working Group
5 June 2013	Connections Working Group
1 July 2013	GEMA launches an open letter on the RIIO-ED1 business

Date	Event
	plans that the DNOs have submitted.
4 September 2013	GEMA consults on the levels of reward/penalty that DNOs are to get under the RIIO-ED1 customer service and connection incentives.
4 October 2013	GEMA consults on whether there is benefit in making its decision on revenue to be recovered by DNOs in 2015/16 earlier than proposed.
18 October 2013	Environment Working Group
8 November 2013	Customer and Social Issues Working Group
20 November 2013	Connections Working Group
22 November 2013	GEMA publishes its assessment of the 14 DNO business plans for RIIO-ED1 and considers that only WPD's plans are of sufficient quality to be fast-tracked.
22 November 2013	GEMA publishes the Draft Determinations for WPD's fast-track price control settlement.
6 December 2013	GEMA consults on its methodology for assessing equity market return for the purpose of setting RIIO price controls in light of the CC's provisional determination for Northern Ireland Electricity.
4 December 2013	Environment Working group
11 December 2013	GEMA issues its decision on the levels of reward/penalty that DNOs are to get under the RIIO-ED1 customer services and connections incentives.
19 December 2013	GEMA issues its decision on when it will set the revenue to be recovered by DNOs in 2015/16.
10 January 2014	GEMA launches the first part of an informal consultation on fast-track licence drafting in respect of proposed changes to the Charge Restriction Conditions ("CRCs") affecting the four licensees owned by WPD.
10 January 2014	GEMA launches informal consultation on proposed changes to Standard Licence Conditions ("SLCs") required to implement RIIO-ED1 price control review for all DNOs.
22 January 2014	Connections Working Group
22 January 2014	Customer and Social Issues Working Group
31 January 2014	GEMA launches the second part of its informal consultation on fast-track licence drafting in respect of proposed changes to the CRCs affecting the four licensees owned by WPD.
17 February 2014	GEMA issues its decision on the methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls.
27 February 2014	GEMA issues its decision to fast-track WPD.
27 February 2014	GEMA published the Final Determinations for the four licensees owned by WPD.

Date	Event
28 February 2014	GEMA sets out provisional values for the Network Innovation Allowance ("NIA") to which each DNO will be entitled in RIIO-ED1 (DNOs use the NIA to fund small-scale innovation projects).
March 2014	The five remaining "slow-track" DNO groups submit revised business plans.
7 March 2014	GEMA consults on the draft RIIO-ED1 Environment Report guidance document.
28 March 2014	GEMA commences statutory consultation on proposed modifications to the CRCs of the electricity distribution licences held by the four licensees owned by WPD.
28 March 2014	GEMA commences statutory consultation on proposed modifications to the SLCs of the electricity distribution licences which implement the policies described in the strategy decision dated 4 March 2013.
31 March 2014	GEMA launches open-letter consultation on revised RIIO-ED1 business plans submitted by five DNO groups.
21 May 2014	GEMA publishes modification notice amending the SLCs of the electricity distribution licences for RIIO-ED1.
21 May 2014	GEMA publishes modification notice amending the CRCs of the electricity distribution licences held by the four licensees owned by WPD for RIIO-ED1.
30 July 2014	GEMA publishes its draft determinations for the slow-track electricity distribution companies for RIIO-ED1.
28 August 2014	GEMA consults on the treatment of RPEs in the revenue allowances proposed for slow-track DNOs for RIIO-ED1.
18 September 2014	Reliability and Safety Working Group
26 September 2014	GEMA launches informal consultation on changes to DNOs' SLCs for RIIO-ED1 that was not part of first consultation dated 21 May 2014.
26 September 2014	GEMA launches informal consultation on proposed changes to CRCs required to implement the RIIO-ED1 price control settlements for slow-track DNOs.
28 November 2014	GEMA publishes final determinations for RIIO-ED1 for the slow-track electricity distribution companies.
4 December 2014	GEMA consults on the Incentive on Connections Engagement (ICE) guidance document.
16 December 2014	GEMA consults on the Stakeholder Engagement and Consumer Vulnerability (SECV) incentive (Closed 16 January awaiting decision)
17 December 2014	GEMA publishes corrections to elements of the RIIO-ED1 Final Determinations suite of documents for slow-track DNOs.
17 December 2014	GEMA commences statutory consultation on proposed

Date	Event
	modifications to the CRCs of the electricity distribution licences of the DNOs in the slow-track process.
7 January 2015	GEMA consults on the assessment of the benefits from the roll-out of proven innovations through the Innovation Roll-out Mechanism (Closed 4 March awaiting decision)
28 January 2015	GEMA consults on the draft RIIO-ED1 Environment Report guidance document (Closed 25 February awaiting decision)
28 January 2015	GEMA issues an informal consultation on the draft regulatory instructions and guidance for the electricity distribution licensees.
3 February 2015	GEMA consults on updates under CRC 4C (Price control update provisions) for the electricity distribution licences held by the four licensees owned by WPD.
3 February 2015	GEMA issues decision to modify the CRCs of the electricity distribution licences of the DNOs in the slow-track process.
25 February 2015	Incentive on Connections Engagement (ICE) guidance document decision.
4 March 2015	Directions under Parts A and D of CRC 4C (Price control update provisions for WPD) of WMID's, EMID's, SWALES's and SWEST's electricity distribution licences.

ANNEX 3

ERRORS IN FRONTIER REPORT

The errors or incomplete descriptions in the Frontier report are, in the order that they appear, as follows:

1. In paragraph 2.17, Frontier states that "Table 2 below shows the total adjustments made to each DNO's submitted costs across the 13 year period included in the Authority's costs assessment." In fact, Table 2 only shows the adjustments for regional labour differentials across the eight years of RIIO-ED1. In addition, in paragraph 2.17 Frontier states that "NPg operates in the Rest of GB region (i.e. GB excluding London and the South East) where GEMA considers there are relatively low labour costs". In fact, the Authority did not merely "consider" the labour cost to be relatively low. Its conclusion in this regard was supported by evidence collected from the ONS Annual Survey of Hours and Earning (ASHE) and analysed by the Authority, which showed a clear labour premium in London and the South East.

2. In paragraph 2.27, Frontier states that any errors in pre-modelling adjustments would result in the outcomes of the model not accurately reflecting the DNOs' actual relative efficiency. While this is factually correct, Frontier fail to make clear that if the Authority did not make these adjustments its relative efficiency estimates would most likely be materially less accurate than if there were any errors in the adjustments.

3. In the first bullet point of paragraph 2.30 Frontier notes that the Authority's RIIO-ED1 approach differs from its RIIO-GD1 approach in its use of historical data in that it calculates the DNOs' RIIO-ED1 efficiency based on a ratio of the DNOs' forecast costs to Ofgem's modelled costs rather than including historical (DPCR5) performance as well. The Authority has two concerns with this statement:

   (a) First, Frontier's assertion that "no historical performance was incorporated into GEMA's assessment of the DNO's efficiency" is incorrect. The DNOs' historical performance fed into Ofgem's models, thereby helping set Ofgem's modelled costs. This is a particularly

important aspect in the disaggregated modelling, where changes over DPCR5 were used to set Ofgem's view of DNOs' RIIO-ED1 requirements.

(b) Secondly, the RIIO-ED1 modelling approach was an evolution from RIIO-GD1. In the latter, Ofgem assessed only using forecast models, but these were not found to be robust. Ofgem considered that data from the DNOs had been collected on a sufficiently robust basis to produce reliable results for RIIO-ED1.

4. In relation to the second bullet point of paragraph 2.30, the Authority notes, similarly to its response to paragraph 2.27, that using unadjusted costs to calculate efficiency scores would have been incorrect. This would have produced less accurate results than if there were any errors in the Authority's adjustments.

5. In paragraph 2.31, Frontier states that "GEMA calculated the combined efficiency score by weighting the efficiency scores from the three models." While this is in essence what happened, the actual calculation was to weigh together the difference between Ofgem's view and the DNOs' submission for each of the three models.

6. The Authority has concerns with Frontier's language in paragraphs 2.37 to 2.41. In paragraph 2.37 Frontier refers to "combined benchmark cost, post-reversal of adjustments." This is incorrect. This cost is not a "benchmark cost": rather it is the cost produced by the modelled cost with the pre-modelling adjustments reversed. At this stage no adjustment has been made for the upper quartile. Therefore, Frontier's statement that the upper quartile being below one "had the impact of reducing the benchmark cost for all DNOs" in paragraph 3.40 is misleading.

7. In paragraph 2.51, where Frontier notes that SGBs were included in the calculation of the efficiency scores and assessed separately, Frontier fails to note that the additional adjustment was undertaken in such a way that avoided double counting savings in both the comparative assessment and the SGBs assessment.

8. In paragraph 2.61, Frontier presents an example of how NPg may have been rewarded if its 'IQI ratio' (the difference between its submitted costs and Ofgem's view) had been 100; implying that NPg would have been heavily rewarded. This is a misleading example. As clearly set out in the Draft Determination, the IQI breakeven point was shifted (from 100 to 102.9) as no DNOs were found to have submitted costs in line with the Authority's view of efficient cost. Therefore, if NPg had submitted efficient costs (i.e. an IQI ratio of 100) it is highly unlikely that there would have been a need to shift the breakeven point and so NPg would not have received any upfront reward/penalty.