BEFORE THE COMPETITION AND MARKETS AUTHORITY

IN THE MATTER OF AN APPEAL UNDER ARTICLE 14B OF THE ELECTRICITY (NORTHERN IRELAND) ORDER 1992

B E T W E E N :

SONI LIMITED

Appellant

and

THE NORTHERN IRELAND AUTHORITY FOR UTILITY REGULATION

Respondent

NOTICE OF APPEAL
ENERGY LICENCE MODIFICATION
SONI TSO PRICE CONTROL 2015 - 2020

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Glossary

Term	Definition
BGT Determination	Final determination of the Competition and Markets Authority in relation to the British Gas Trading Limited price determination, published on 29 September 2015 (https://assets.publishing.service.gov.uk/media/5609588440f0b6036a00001f/BGT_final_determination.pdf)
Business Plan	The Appellant's Business Plan as submitted to the Utility Regulator on 21 October 2014
capex	Capital expenditure
CAPM	The capital asset pricing model is a model that describes the relationship between systematic risk and expected return for assets.
CC	Competition Commission, replaced from 1 April 2014 by the CMA
CEPA	Cambridge Economic Policy Associates Ltd
CMA	Competition and Markets Authority
CPI	Consumer Price Index, a measure of inflation published monthly by the Office for National Statistics
curtailment	Curtailment refers to the dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem)
DB	Defined Benefit
DBC	Dispatch Balancing Costs. These constraint payments keep generators financially neutral for the difference between the market schedule and what actually happened when generating units were dispatched. Generators can be constrained "on" or "up", if the market schedule indicated they were to be run at lower levels than actually happened, or they can be constrained "down" or "off" if they were to be run at a higher level than happened in reality. There is always an overall net cost to the system associated with constraints.
DC	Defined Contribution
The Department	Department for the Economy (Northern Ireland), previously the Department of Enterprise, Trade and Investment
DIWE	Demonstrably Inefficient and Wasteful Expenditure, a licence mechanism introduced by the Licence Modifications pursuant to which the Utility Regulator may determine adjustments to the Appellant's maximum regulated revenue or RAB in connection with costs that it assesses to be "*demonstrably inefficient or wasteful*"
DS3 Programme	"Delivering a Secure Sustainable Electricity System", a programme designed by EirGrid and SONI in response to binding national and European targets which aims to put in place the required changes to system policies, tools and performance to allow the electricity system to operate safely with a high penetration of non-synchronous generation

Term	Definition
E.ON v GEMA	E.ON UK Plc and GEMA and British Gas Trading Limited: Decision and Order of the Competition Commission (Case CC02/07) (10 July 2007) (https://assets.publishing.service.gov.uk/media/55194bf440f0b6140400036a/eon_final_decision.pdf)
EC Decision	European Commission decision of 12.4.2013 pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC – United Kingdom (Northern Ireland) – SONI/NIE (https://ec.europa.eu/energy/sites/ener/files/documents/2013_059_uk_en.pdf)
EirGrid	EirGrid plc – since 2006, EirGrid has operated and developed the national high voltage electricity grid in the Republic of Ireland. EirGrid is owned by the Irish State
EirGrid Group	The EirGrid corporate group, which includes EirGrid, SONI, SEMO, EirGrid Interconnector DAC and EirGrid Telecoms DAC
Electricity Directive or IME3	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 OJ 2009 L211/55 (also known as the "**Third Internal Market in Electricity Directive**")
Electricity Order	The Electricity (Northern Ireland) Order 1992 SI 1992/231
Energy Efficiency Directive	Directive of the European Parliament and Council 2012/27/EU on energy efficiency, amending Directive 2009/125/EC and 2010/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC OJ 2012 L315/1
Energy Order	The Energy (Northern Ireland) Order 2003 SI 2003/49
ENTSO-E	European Network for Transmission System Operators for Electricity
EU Third Energy Package	A package of EU energy market legislation (including the Electricity Directive), which was enacted to improve the functioning of the internal energy market and to resolve structural problems, in particular by way of unbundling energy suppliers from network operators. For further details see https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation
GEMA	Gas and Electricity Markets Authority
IS (or IT)	Information Systems or Information Technology, i.e. the software systems and technologies required to enable SONI's TSO functions
I-SEM	Integrated Single Electricity Market for Northern Ireland and the Republic of Ireland, the new wholesale electricity market for the island of Ireland which is scheduled to go live in May 2018 and is overseen by the SEM Committee. For further details see https://www.semcommittee.com/i-sem
Network Planning	Includes activities required to progress a transmission project from the conceptual stage through to the point where project construction commences – specifically Phases 1 (Project Identification) and 2 (Pre-Construction activities) of transmission connection and development connection projects. The Network Planning Function formally transferred from NIE to SONI on 1 May 2014 at the direction of the Utility Regulator

Term	Definition
NIE	Northern Ireland Electricity Networks Limited, owner of the electricity transmission and distribution network and operator of the electricity distribution network in Northern Ireland (previously known as Northern Ireland Electricity Limited)
NIE Determination	Final determination of the Competition Commission in relation to the NIE price determination, published on 26 March 2014 (https://assets.publishing.service.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf)
NPG Determination	Final determination of the Competition and Markets Authority in relation to the Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc price determination, published on 29 September 2015 (https://assets.publishing.service.gov.uk/media/5609534de5274a036c000012/NPg_final_determination.pdf)
Ofgem	Office of Gas and Electricity Markets
Ofwat	The Water Services Regulation Authority
opex	Operational expenditure
PCG	Parent Company Guarantee. Condition 3A of the Licence requires the Appellant to procure an undertaking from EirGrid, in a form approved by the Utility Regulator, to ensure that the Appellant has adequate financial and non-financial resources to perform its obligations and meet any liabilities under the Licence. In fulfilment of this requirement EirGrid provided a £10 million PCG when it acquired the Appellant.
PCNP and PCNPs	Pre-construction transmission network project(s)
Phoenix Gas Determination	Final determination of the Competition Commission in relation to the Phoenix Gas price determination, published on 28 November 2012 (https://assets.publishing.service.gov.uk/media/551948b8e5274a142b000186/phoenix_natural_gas_limited_price_determination.pdf)
Price Control	The price control for the SONI TSO business which was due to start on 1 October 2015 and run until 30 September 2020
Price Control Period	Duration of the Price Control, initially proposed by the Utility Regulator to start on 1 October 2015 and run until 30 September 2020
Protected Persons Regulations	The Electricity (Protected Persons) Pension Regulations (Northern Ireland) 1992 SR 1992/93
RAB	Regulated asset base
Regulations	The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015 SR 2015/1
ROCE	Return on capital employed
RORE	Return on regulated equity

Term	Definition
RPI	Retail Price Index, a measure of inflation published monthly by the Office for National Statistics
SEM	Single Electricity Market, the wholesale electricity market for the island of Ireland which is jointly regulated by the Utility Regulator and Commission for Energy Regulation and governed by the SEM Committee. The SEM consists of a gross mandatory pool market, into which all electricity generated on or imported onto the island of Ireland must be sold, and from which all wholesale electricity for consumption on or export from the island of Ireland must be purchased
SEM Committee	A committee of the Utility Regulator which is the decision making authority for all SEM matters, consisting of up to three Commission for Energy Regulation and up to three Utility Regulator representatives along with an independent and a deputy independent member
SEM Matter	Per Article 6(3) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 SI 2007/913, a matter is a SEM matter if the SEM Committee determines that the exercise of a relevant function of the Utility Regulator in relation to that matter materially affects, or is likely materially to affect, the SEM
SEMO	Single Electricity Market Operator. SEMO facilitates the continuous operation and administration of the Single Electricity Market. SEMO is a joint venture between EirGrid plc and SONI Limited. The organisation is managed as a contractual joint venture between EirGrid, the TSO for Ireland, and SONI, the TSO for Northern Ireland. SEMO is licensed and regulated cooperatively by the Commission for Energy Regulation (CER) in Ireland and the Utility Regulator in Northern Ireland through their respective SEM Committees. For further details see http://www.sem-o.com/AboutSEMO/Pages/default.aspx
SNSP	System Non-Synchronous Penetration
SONI Grid Code	The SONI Grid Code sets out the legal and contractual framework for the transmission of electricity and governs the balancing of the transmission system to achieve lowest cost of production
SSS	System Support Services tariff. A charge per kWh for each unit delivered through the Transmission System at the trading point designed to recover the costs of operating the Transmission system including the costs of ancillary services. The SSS tariff is published annually in the Transmission Statement of Charges and is a flat rate tariff. The SSS charge is levied on Suppliers only.
System Services	A key area of the DS3 Programme. SONI seeks to ensure that the electricity system operates securely and efficiently, while facilitating the transmission of higher levels of renewable energy. To achieve this, SONI works to obtain services from generators and market participants
TAO	Transmission Asset Owner, which is NIE pursuant to the arrangements in Northern Ireland
TIA	Transmission Interface Arrangements, which were designed to facilitate working arrangements between NIE (as transmission owner and/or distribution network owner) and SONI (as TSO). Changes to the terms of the TIA must be approved by the Utility Regulator

Term	Definition
TSC	SEM Trading and Settlement Code, which was developed during the establishment of the SEM and provides the rules by which the market and its participants may operate, setting out the detailed rules and procedures concerning the sale and purchase of wholesale electricity in the SEM
TSO	Transmission System Operator
TUoS	Transmission Use of System tariff
TUPE	The Transfer of Undertakings (Protection of Employment) Regulations 2006 SI 2006/246 and the Service Provision Change (Protection of Employment) Regulations (Northern Ireland) 2006 SR 2006/177
Utility Regulator	Northern Ireland Authority for Utility Regulation, sometimes referred to as NIAUR
WACC	Weighted average cost of capital

PART I

OVERVIEW AND INTRODUCTION

1 Overview

1.1 The Appellant, SONI Limited (**SONI**), is the independent electricity transmission system operator (**TSO**) for Northern Ireland.

1.2 In this Notice of Appeal (**Notice**), the Appellant adopts the defined terms listed in the Glossary.

1.3 The Appellant is licensed to participate in the transmission of electricity by the Department for the Economy (the **Department**), in exercise of the powers conferred by Article 10(1)(b) of the Electricity Order. The relevant licence will be referred to as the **TSO Licence**.

1.4 The Appellant's TSO business is subject to a regulated price control. The Utility Regulator, which is the Respondent, is responsible for regulating the Appellant as TSO and for setting its TSO price control.

2 Request for permission to appeal

2.1 By this Notice the Appellant seeks permission from the CMA under Articles 14B(1) and (3) of the Electricity Order to bring an appeal against the decision of the Utility Regulator, made under Article 14 of the Electricity Order, to make modifications to the TSO Licence, as published on 14 March 2017 (the **Decision**).[1] The Appellant appeals as a relevant licence holder and therefore has legal standing to bring an appeal.

2.2 The Decision is intended to give effect to the arrangements determined by the Utility Regulator in respect of the 2015-2020 price control for the SONI TSO business (the Price Control), as set out in the Final Determination published by the Utility Regulator on 24 February 2016 (the **Final Determination**).[2] Most unusually, this Decision was adopted more than a year after the Final Determination and nearly 18 months after the intended start date of 1 October 2015. The Final Licence Modifications, and hence the Price Control, are scheduled to take effect on 9 May 2017 but the Appellant also seeks suspension of the Decision pending determination of this Appeal. The suspension request has been made by way of separate notice pursuant to paragraph 2(2) of Schedule 5A of the Electricity Order.

2.3 At the outset it is important for the Appellant to emphasise that it has serious reservations about the conduct of the Licence Modification process. The Appellant had every right to expect that the Utility Regulator would conduct itself in accordance with the well-established principles of good regulation. Indeed, the Utility Regulator considers its approach to the price control

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1 Utility Regulator, "*Decision on the Licence Modifications for the Price Control 2015-2020 of the Electricity System Operator for Northern Ireland (SONI)*", 14 March 2017 (the **Decision Paper**) [**NOA1/18**] and "*Modifications to SONI Limited's Electricity Transmission Licence*", 14 March 2017 (the **Final Licence Modifications**) [**NOA1/17**].

2 Utility Regulator, "*Final Determination to the Price Control 2015-2020 for the Electricity System Operator for Northern Ireland (SONI)*", 22 February 2016 **[NOA1/12]**.

framework to be consistent with these principles.[3] Unfortunately, this is not the case. These principles include “accountability”, “predictability” and “coherence”.[4]

2.4 In what follows the Appellant will demonstrate that, following the Final Licence Modifications, certain powers vested in the Utility Regulator over the regulatory period, involving very significant elements of the revenues needed by the Appellant, will not be subject to review or appeal, still less by the CMA, because they would not be licence modifications but merely the exercise of powers by the Utility Regulator within the modified licence and thus escape scrutiny by the CMA. Thus, irrespective of the impact on revenues, the Utility Regulator can act with no accountability whatever. This is in clear breach of the principle of “accountability”. Allied to this, the exercise of the discretionary and unreviewable powers of cost review and cost capping, especially in the absence of any consultation or guidance as to their exercise, is a clear breach of the principle of “predictability”. The Final Determination and Decision also are at variance with, or neglect, the policy imperatives, discussed below, under which the Appellant will act over the period and are therefore in breach of the principle of “coherence”.

2.5 The lengthy and inexplicable gestation period of the Final Determination, and the abnormally long period which elapsed before the Decision finally emerged (and even then incomplete, as described below) – also brings into question adherence to the principle of “efficiency” of the decision-making capacity of the Utility Regulator. That overall delay has also added to the uncertainty, further undermining the financeability of the Appellant. In addition, the Utility Regulator appears to have been subject to some confusion concerning the exercise of its functions, including as to whether matters were, or were not, “SEM matters”. Thus, throughout the process, the Utility Regulator has not conducted itself in accordance with these principles. Some instances of this will be highlighted below and will be further detailed in this Notice.

2.6 The principles of good regulation have been universally adopted by regulators in the UK and, in the majority of cases, are enshrined in statute. This is not the case in Northern Ireland but not, it is submitted, because it was thought right that the Northern Ireland regulator should operate wilfully neglecting such principles. Rather, it is clear from the decisional practice of the CMA (and previously the CC) that such principles apply, a point affirmed by the CC in the Phoenix Gas Determination. These repeated failures to observe these principles constitute the optic through which the CMA is invited to approach this appeal.

2.7 The CMA will further note that in important respects the Price Control remains incomplete despite the length of time taken. The Utility Regulator has indicated it has decided to consult further on certain matters, under an indeterminate timetable, notably on pensions, while still making provision for pension liabilities which SONI believes to be inadequate and which form part of this appeal.

3 Final Determination, paragraph 17 **[NOA1/12]**.

4 See the five principles set out by the Better Regulation Taskforce in 1997 in “*Principles of Good Regulation”*, and in paragraph 12 of the *Principles for Economic Regulation* published by the then UK Department for Business, Innovation and Skills in April 2011 (available at http://webarchive.nationalarchives.gov.uk/20100407162704/http:/archive.cabinetoffice.gov.uk/brc/upload/assets/www.brc.gov.uk/principlesleaflet.pdf and https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/31623/11-795-principles-for-economic-regulation.pdf).

2.8 The unsatisfactory and impractical nature of the Utility Regulator's decision to consult further offers no comfort to the Appellant. Nor does its invitation to simply come back and ask for additional funds if needed.[5] The Utility Regulator has, in fact, issued a Decision and, not least in the interests of certainty, the Appellant is proceeding on that basis and is appealing accordingly.

2.9 Finally by way of introduction, the Utility Regulator's principal objective under Article 12(1) of the Energy Order (the **Principal Objective**) is to further the consumer interest. The Appellant takes this to be declaratory of what is obvious. The stress in the Appeal is on the lack of resources to enable the Appellant to deliver a vital service to the electricity industry in Northern Ireland. The consequences of inadequate funding fall on the industry and on consumers. Much will be made below, and in the accompanying evidence, of risk, especially asymmetric risk, and uncertainty, arising first, from inadequate funding and, secondly, because the Utility Regulator has adopted devices in the price control which add to risk and uncertainty. That greater risk and uncertainty is a direct consequence of a Final Determination and Decision Paper which fail to remunerate capital and so frustrate the flow of new and needed capital at a time where it is needed to fulfil regulatory and public policy decisions. As explained in the First Witness Statement of Aidan Skelly (**AS1**) the upshot is that the banks, formerly sympathetic, are unwilling to lend money to the Appellant absent a cross-guarantee from EirGrid or a Letter of Comfort from the Utility Regulator. Among other consequences, this threatens the curtailment of the DS3 programme of renewables and possible delays in the delivery of I-SEM. These consequences have to be matched against the mere 70p annual reduction in electricity bills claimed by the Utility Regulator, and a judgement has to be made that that sum, and more, might be better deployed in ensuring that the Appellant meets its obligations, on which Northern Ireland and its consumers rely.

Structure of this Notice

2.10 This Appeal is primarily founded on the Utility Regulator's failure to secure the Appellant's financeability, in breach of its obligations under Article 12(2) of the Energy Order (the **Financeability Duty**).

2.11 Part I of this Notice provides an overview of the basis on which the Appellant brings its Appeal. Part II summarises the relevant statutory framework and the test which the CMA should apply on order to determine the Appeal. Part III sets out the Price Control formula. Part IV explains the Appellant's Grounds of Appeal in detail and, in particular, shows how the Price Control arrangements proposed by the Utility Regulator ultimately fail to secure that the Appellant's TSO business is financeable and describes the immediate and future impact on the Appellant of the Price Control proposed by the Utility Regulator. Part V sets out the relief sought by the Appellant.

3 Context of this appeal

(a) SONI Limited

3.1 The Appellant was incorporated as SONI Limited in 2000. It was previously owned by Northern Ireland Electricity (now **NIE**), which owns the Northern Ireland transmission system, and was acquired by its current ultimate parent company, EirGrid Plc (**EirGrid**), which holds the licence

5 Letter from the Utility Regulator to the Appellant dated 31 March 2017 exhibited as [**RJM/7**] to RJM1.

for transmission system operation in the Republic of Ireland, in March 2009. As explained in AS1, in the past, it has been financed partly by private sector bank term debt, or various revolving credit instruments, as the enterprise is too small to make a bond issue viable even if the security existed to allow such an issue, and by equity capital provided by EirGrid, which is ultimately owned by the Irish State. In March 2014 the Appellant assumed responsibility (and the associated risks) for Network Planning of the Northern Ireland transmission system (the **Network Planning Function**) from NIE. Further detail regarding EirGrid and the acquisition of the Appellant by EirGrid can be found in the First Witness Statement of Fintan Slye (**FS1**).

3.2 The Appellant is unusual in that, as the operator of the transmission system, it does not own the transmission system itself. This is owned by NIE, which also owns and operates the electricity distribution network in Northern Ireland.[6] By contrast, the arrangements in Great Britain are that National Grid plc owns the transmission network[7] and also assumes responsibility for the system as TSO.

3.3 As the holder of a transmission licence under Article 10(1)(b) of the Electricity Order, the Appellant is under a statutory duty, pursuant to Article 12(2) of the Electricity Order, to:

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

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

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

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

3.4 Pursuant to Articles 12(1) and 12(2) of the Energy Order, the Utility Regulator and the Department are subject to analogous statutory obligations.

3.5 As the licensed TSO for Northern Ireland, the Appellant's core functions include the operation of the Northern Ireland transmission network (including both near time and real time operation of the system), balancing the physical system to achieve the lowest cost of production (including outage planning both for transmission and generation outages), the facilitation of payments within the system, I-SEM, DS3 and the Network Planning Function (i.e. planning investment in the transmission network based on the Transmission System Security and Planning Standards approved by the Utility Regulator, from identification of need through to obtaining all necessary construction consents, as discussed in AS1).

3.6 As part of these functions, the Appellant works closely with NIE in respect of the development of the transmission system, including to assess the impact of connections on the transmission

6 NIE is owned by the Electricity Supply Board (**ESB**), a publicly-owned statutory corporation in the Republic of Ireland and holder of the transmission asset owner licence in that jurisdiction. EirGrid is managed independently of ESB. The structural relationship between the two companies is confined to their common public ownership by the Irish Government. The issued share capital in both EirGrid and ESB is held by or on behalf of each of the Ministers for Public Expenditure and Reform and for Communications, Climate Action and Environment.

7 In England and Wales but not Scotland.

system in order to determine if any reinforcements are required to be made to the network in furtherance of the Network Planning Function. IME3 (i.e. the EU Third Internal Energy Package Directives) requires that the Appellant must produce a ten year network development plan.[8]

3.7 Of less relevance to this appeal (except concerning the issue of a shared Parent Company Guarantee required under Condition 3A of SONI's Licence discussed below[9]) the Appellant holds a separate licence (the **SEMO Licence**) as operator of the wholesale electricity market in Northern Ireland and Ireland, the SEM. That licence covers a different set of activities and refers to different functions and is subject to a separate set of price control arrangements determined by a committee of the Utility Regulator known as the SEM Committee (**SEM Committee**). The Appellant carries out its SEMO Licence functions, which are quite distinct from its functions under the TSO, through a contractual joint venture with EirGrid, namely SEMO, in which SONI has 25 per cent and EirGrid has 75 per cent of the capital.[10]

3.8 As explained in AS1, the Appellant is the contractual counterparty for system users and is responsible for calculating charges for access to the transmission system in line with methodology approved by the Utility Regulator. The Appellant collects this TUoS tariff from all system users. The tariff is paid by all-island generators and Northern Ireland customers. The Appellant also collects the System Services Payments, which amounts to a charge per kWh for each unit delivered through the transmission system at the trading point designed to recover the costs of operating the transmission system, including the costs of ancillary services. This charge is published annually and is a flat rate tariff levied on suppliers in Northern Ireland only.

3.9 A feature of this payments structure is that the Appellant is obliged to pay money out on a regular basis, including fixed minimum payments to NIE, yet only receives monies on an irregular basis. The Appellant therefore has a "custodian" or "trustee" function. In the past, stand-by credit facilities have been used to ensure stability of tariffs on an intra year basis. The Appellant told the Utility Regulator that the increased level of activity it faced meant that contingent capital would be expected to increase significantly, potentially trebling over the Price Control, as a result of I-SEM and DS3 System Services. These mismatches give rise to the Appellant needing to manage "liquidity risks", as further explained in AS1.

3.10 In addition revenues are required for the servicing and repayment of loan facilities and investing in capital expenditure. In summary, these concern:

(a) System Services Payments – meaning payments to generators for system performance related services, including provision of generation reserve and reactive power. This is a source of liquidity risk, as explained above;

(b) Dispatch Balancing Costs (**DBC**) – meaning the difference between the constrained and unconstrained market schedules. Where there is a shortfall in revenues to fund the payments, the shortfall must be met by the Appellant, as TSO. However, where excess revenues are collected, the Appellant cannot use these temporary funds to finance its

[8] Article 22 of the Electricity Directive. The Utility Regulator is yet to codify this requirement in the TSO Licence.

[9] See Ground 1, The Financeability Methodology Ground.

[10] SONI's SEM Operator licence is subject to a separate price control; this has however never been finalised and codified in the Licence.

activities. The variations here can be quite marked over quite short periods of time and also create significant additional liquidity risks;

(c) Specific contractual payments entered into under direction from the Utility Regulator – this includes the Local Reserve Services Agreement (**LRSA**) between SONI and a Northern Ireland generator which was required to avoid a potential security of supply issue;

(d) Underlying tariff recovery – related to volumes and climatic conditions; and

(e) Collection Agency Income Requirement (**CAIRt**) – the Appellant acts as Collection Agent in respect of the mutualised Moyle Interconnector Limited (**Moyle**), collecting any income shortfall on behalf of Moyle in order to ensure it is kept whole and can access low cost debt. (The Moyle Interconnector links the electricity grids of Northern Ireland and Scotland through submarine cables running between converter stations at Ballycronan More, Islandmagee, County Antrim and Auchencrosh, Ayrshire).

3.11 The quantum of costs and payments collected and paid out is expected to increase substantially during the Price Control Period, perhaps by as much as three times, owing to industry changes and the key outputs that the Appellant is required to deliver in this period.[11] This role means the Appellant is exposed to significant liquidity risks based on cash flow fluctuations arising from variations in income, costs and timing. These financial risks arise in the form of costs that the Appellant is not directly able to control, as explained in the First Witness Statement of Robin McCormick (**RJM1**).

(b) The regulatory framework

3.12 Under the Energy Order and the TSO Licence, the Utility Regulator has responsibility for setting the revenues the Appellant is allowed to earn as TSO, as well as the outputs it is required to deliver. Both the obligations and the revenues to meet these obligations are then codified in the Appellant's TSO Licence. As such, the price control must allow the Appellant sufficient revenue to finance the activities necessary to meet its licence obligations and to deliver required outputs, whilst also providing the Appellant with incentives to innovate to deliver a low carbon, sustainable energy network at value for money to existing and future customers. The Appellant's recoverable revenues under the TSO Licence are established by reference to the formulae set out in Annex 1 of its TSO Licence (Charge Restrictions), as modified from time to time in accordance with the Electricity Order.

3.13 At the heart of this appeal is the Appellant's concern that the TSO business is not financeable under the Price Control – with the consequence that the Utility Regulator has failed to further the Principal Objective by failing to "secure" the Appellant's financeability, as required by Article 12(2)(b) of the Energy Order (the **Financeability Duty**). These failings are detailed in Part IV of this Notice. In particular, Aidan Skelly explains in AS1 that the Price Control arrangements:

(a) do not provide the Appellant with key revenue streams to cover its financial obligations;

[11] For example, System Services Payments are expected to increase as a result of the DS3 Programme and a new custodian payment stream will be implemented in respect of capacity payments (as a result of I-SEM).

(b) fail to secure the financeability of the Appellant in view of the fact that the banks have refused to lend to the Appellant and EirGrid has no wish to provide further equity capital; and

(c) frustrate the achievement of the objectives of the Appellant under the TSO, including its planned investments in various Significant Projects (as defined below).

3.14 Overall, the shortfall in revenues amounts to £14.7 million – a significant sum in the context of committed funding of only £69 million. This figure includes £7.8 million of allowances which were erroneously disallowed by the Utility Regulator. It also includes provision for non-recovery of certain revenues "at risk" under the Decision relating to significant capital expenditure and network planning (amounting to approximately £1.5 million). Finally, it includes the shortfall arising when the WACC*RAB framework is compared to a benchmarked EBIT margin of 11 per cent of controllable costs, amounting to a further approximately £5.3 million which investors are denied but might reasonably expect to receive. The Appellant is therefore not financeable under the Utility Regulator's Decision.

3.15 As Aidan Skelly explains in AS1, the Utility Regulator has created an unsustainable set of arrangements with the result that there is simply not enough revenue to compensate capital providers and ensure the continued remuneration for the financing necessary to operate and fund its business operations. Absent correction by the CMA, in the absence of bank support or additional funding from EirGrid it is possible that the Appellant's business will have to be significantly restructured, as discussed in AS1. It is also likely that in order to raise sufficient capital to fund the necessary investments that the Appellant will have to consider disposing of assets or issuing new capital. It is wholly unclear that the Appellant will obtain additional support from EirGrid during the Price Control Period if the appeal is unsuccessful.

3.16 The Parent Company Guarantee (PCG) is itself a very unusual stipulation, but one stipulated by the Utility Regulator pursuant to the direction of its SEM Committee which considered this would provide "the requisite comfort that SONI would be able to finance its regulated activities and deal with financial "shocks" or major outlays as and when they arise".[12] This solution was acknowledged to be a cheaper alternative to the Appellant achieving investment grade status but nonetheless confirms that if the Appellant were viewed as a "standalone" entity it would not be financeable. While a PCG from EirGrid is a licence condition, there is no provision in the TSO Licence requiring yet further support. More egregiously, notwithstanding the requirement to provide this layer of capital to the Appellant, the Utility Regulator refuses to remunerate this capital. It does so, on the false ground that the PCG attracts a return in respect of the risks run under the SEMO Licence, discussed above, which are in respect of a different set of functions and risks. In any event the Appellant has not been provided with a codified price control for its SEMO Licence. While the EirGrid Board has agreed to make loans pending the resolution of the price control appeal, the Appellant's evidence shows that it cannot be relied upon indefinitely to fill the financial gaps left by the Utility Regulator as confirmed by Fintan Slye:[13]

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12 SEM Committee, "*The Proposed Acquisition of SONI Limited by EirGrid plc – A Consultation Paper*", 18 December 2008, paragraph 36 (available at https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-08-176.PDF).

13 Paragraph 40, FS1.

The EirGrid board is not therefore prepared, and in my view is unlikely to be in a position to, keep bankrolling SONI perpetually in the context of the price control, associated risk profile and assumed equity returns of less than £1 million per annum.

3.17 The Appellant considers that a major factor contributing to this outcome is the Utility Regulator's unreasoned dedication to a regulatory framework (RAB*WACC), which is not fit for purpose given the Appellant's particular circumstances and business structure. The Utility Regulator has failed to grasp the profound changes which have taken place since the Appellant's functions were abstracted from NIE in 2009 and, in particular, since the Network Planning Function was transferred from NIE to SONI in 2014. As explained in AS1, when the Utility Regulator was assessing the appropriate price control for the Appellant in relation to the 2010 to 2015 period (a decision which was not issued until 2012)[14], it did not take any account of the new structure following divestment of the Appellant from NIE in 2009 and simply rolled forward the previous control. Accordingly, the Price Control, which relates to the 2015 to 2020 period, and which forms the subject of the appeal sought to be made by the Appellant, will be the first price control which takes account of:

(a) the Appellant's position as a stand-alone TSO that is no longer integrated within the corporate structure of a transmission asset-owning group; and

(b) the Appellant's network planning function.

3.18 In addition, as explained in AS1, there have been changes to the capital structure and financial situation of the Appellant over this period. In the period 2010/11 to 2014/15 it generated adequate profits which were driven by two factors. First, regulatory depreciation allowance was some £10 million higher than the accounting depreciation owing to a regulatory decision to shorten asset lives. So some 40 per cent of the 2010-2015 EBIT represented a timing difference on the return of the Appellant's capital rather than underlying profitability. The acceleration of regulatory depreciation will be largely completed by 2015/16. The second factor was opex efficiencies achieved as a result of group integration and expense sharing with EirGrid. The Appellant used the profits to pay down debt and fund investments in non-network assets. There were no large scale investment commitments since investment in SEM in 2007. No dividends were paid to EirGrid.

3.19 The Appellant does not own significant infrastructure or hold transmission assets on its balance sheet. It has no significant RAB[15], equity return, or balance sheet upon which to lever investment. The RAB fell by more than 50 per cent between 2009 and 2015, reaching £8.9 million at the commencement of the Price Control Period. This means that the Appellant does not have the large stream of steady income which accompanies a large RAB. The errors made by the Utility Regulator in failing to secure the Appellant's financeability – giving rise to a shortfall of £14.7 million – must be seen in this context. The Appellant is highly operationally geared meaning even a modest shortfall in revenues extinguishes the expected return. On this basis, the Appellant is a risky business if it is obliged to rely on a RAB-based return. It is riskier still if it is obliged to add new and expensive responsibilities to its activities, such as Network

[14] "SONI Price Control 2010-2015 Decision Paper" (**2010-2015 Decision Paper**) **[NOA1/6]** and "Licence to participate in the transmission of electricity granted to SONI Limited (Updated to May 2012)" **[NOA1/7]**.

[15] Any figure for a RAB is at best an incomplete representation of the value-added within the Appellant derives from its highly skilled workforce, their know-how, and the sophistication of the underlying IT systems, whereas the RAB places a value on network assets.

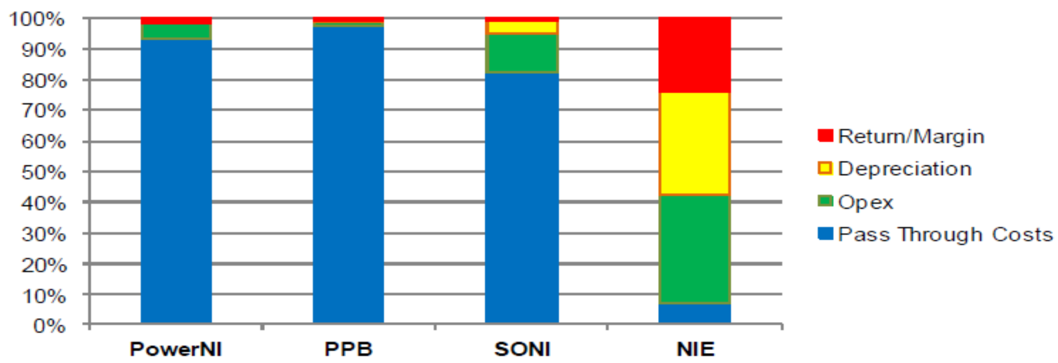
Planning, activities where, as shown below and in AS1, costs are inherently uncertain. This is compounded by the fact that, notwithstanding the transfer of certain key personnel from NIE, there will nevertheless be a period of adjustment as the Appellant develops the programme of work to discharge its new responsibilities.

3.20 As discussed in further detail in Part IV, Ground 1, the Financeability Methodology Ground[16] and the First Witness Statement of Bill Thompson (**BT1**) there was some expectation that, given these changes and challenges, a regulatory model more suited to the Appellant's capital structure and operations would be introduced in this price control and, in particular, the RAB*WACC model that had applied when the Appellant was part of NIE's Transmission and Distribution business would be replaced by a more suitable model for a company with such a thin RAB.

3.21 The Utility Regulator dismissed these proposals and failed to adopt a price control framework which *would* have secured the Appellant's financeability. It closed its mind to applying a model suited to the Appellant's business characteristics and so proceeded with a model which serves to underestimate the revenues required and adds to the existing risks and uncertainty in the Price Control Period.

3.22 In the Final Determination the "building blocks" of the Appellant's allowed revenue are calculated in the same way as in many other regulated utilities: capital expenditure (**capex**), operating expenditure (**opex**), depreciation and return based on regulated asset base (**RAB**), multiplied by the weighted average cost of capital (**WACC**). However, there are significant differences between the split of revenue across these building blocks for the Appellant as compared to a typical large asset-based utility. These differences are illustrated at Figure 1 below, which demonstrates that the Appellant has a comparatively high level of pass-through costs and on the proportion of revenues derived from the RAB is small in comparison to overall revenues, in contrast with NIE the TAO and as such is more akin to other service provider organisations such as Power NI and the Power NI Energy Power Procurement Business (**PPB**) which are both regulated on a non WACC*RAB basis.[17]

Figure 1: Comparison of cost and revenue splits between asset-heavy and asset-light NI regulated businesses



16 See paragraph 4.3(a).

17 Business Plan, Appendix 10: CEPA, "Power NI 2014 Price Review: Financeability and its implications for a required profit margin: Final Report", March 2013, **tab 23 of [BT1/31]**

3.23 The focus of the RAB*WACC model is the efficient funding of network assets. However, as Aidan Skelly explains in further detail in AS1, the "asset light"' nature of the Appellant's business means it does not own any significant infrastructure or hold transmission network assets on its balance sheet and therefore the layer of capital actually remunerated under the RAB*WACC framework is very thin compared to the scale of operations, risks and total assets used in the business. The Appellant undertakes significant operational activities but has no significant RAB, equity base, or balance sheet which could act as security for funding. The Appellant has relatively high fixed operational costs (over 60 per cent is payroll, and the remainder is predominantly IT costs and rent). So the absence both of adequate revenue and any security for debt is not favourable to fundraising, as discussed below.

3.24 Further, in the Appellant's view the Price Control does not appropriately reflect the level of risks faced by it in its role as "custodian" of industry revenues (which have a large impact on its cash flow) as the timing and magnitude of payments in and out are not easily predicted, with consequences for contingent and working capital and added exposure for the Appellant. As the Appellant's activities increase in scope, so do the liquidity risks grow. Finally, there is a need for additional capital to support the markedly higher level of investment under the network and non-network capex headings.

3.25 From the beginning of the price control process, therefore, the Appellant was concerned to ensure that a thorough reform of the regulatory framework should be carried out and implemented in this Price Control Period, as explained in Part C of BT1. As examined in further detail in Part IV, Ground 2, the Revenue Uncertainty Ground[18], the Appellant faces an increasingly challenging set of circumstances and has an increasingly complex and central role to play in the Northern Ireland electricity sector. It was of critical importance to the Appellant to ensure that the framework of regulation should be optimal, better to increase the likelihood of the Appellant being financeable. Instead, rather than carrying out the necessary fresh assessment, the Utility Regulator merely rolled forward the existing framework without fully taking into account the importance of the changes which had taken place since 2009, and the substantial changes required to be made to the Northern Ireland electricity network over the course of the 2015 to 2020 period. The Appellant's risk profile and its ability to finance its obligations under the Price Control therefore differ markedly from the previous regulatory period. The end result, and the inevitable consequence of the choice of the wrong framework, is that the Appellant will be underfunded for the tasks and risks it runs over the period.

3.26 Further, even within the framework continued to be adopted by the Utility Regulator, it made a number of errors including failing to remunerate all layers of capital within the business, focusing on an assessment of debt metrics to the exclusion of equity financeability and making a number of modelling errors. Had the Utility Regulator carried out a proper assessment of financeability, the Utility Regulator would have concluded that the Appellant was not financeable under the Price Control arrangements.

3.27 The Utility Regulator has also contributed to greater uncertainty by excluding substantial revenues (estimated at around 35 per cent) in its Decision. This is calculated on the basis of overall allowances having been set at £69 million and sums in the region of £33.3-40.8 million being outstanding, based on estimates of:

[18] See paragraph 4.3(b).

(a) £15 - 20 million in respect of Network Planning;

(b) £11.4 million in respect of I-SEM[19];

(c) £1.9 million in respect of DS3 System Services; and

(d) £5 - 7.5 million in respect of other expected Dt claims.[20]

3.28 The final figure will remain uncertain until sums are separately determined as the Price Control Period progresses. Crucially, the Utility Regulator has not demonstrated in the Final Determination, or the Decision, or anywhere else, that it took the resulting uncertainty arising from the initial exclusion of these costs from the formula into account in assessing the Appellant's financeability. As described in AS1, a constant theme in the Appellant's interaction with banks is their perception that there is no clarity on the likely revenue streams on which security they are being asked to lend. So much is either inadequate, or merely unclear, or held over for scrutiny under the Dt mechanism. Only £6.6 million of capital of the £35-40 million expected to be required over the 2015 to 2020 Price Control period has been codified in the Licence, the rest being subject to the Dt process (described in more detail below). As explained in AS1, the banks also perceive that the Utility Regulator has no awareness of the revenue risks or shocks to which the Appellant may be subject in all its activities especially in the new functions of Network Planning and I-SEM and appears to have carried out no sensitivity analysis in respect of them.

3.29 Finally, the Utility Regulator has failed to fund the Appellant for key allowances in the Price Control, including costs it is legally obliged to meet and which are beyond its control. This is addressed in further detail in Part IV, Ground 3, the Inadequate Allowances Ground[21]. Even excluding the failures identified in the preceding paragraphs, the Appellant does not have the financial headroom[22] to absorb these additional costs. Again, these gaps in the Price Control arrangement do not appear to have been factored into the Utility Regulator's limited financeability assessment.

(c) Challenges and risks faced by the Appellant in the Price Control Period

3.30 The electricity sector in Northern Ireland is in a period of significant transition. This will result in fundamental changes to the generation portfolio in Northern Ireland from an increased reliance on renewables and significant modernisation of the operation of the electricity transmission system. A large part of this change and complexity stems from the implementation of policy goals sent out by the Department in its Strategic Energy Framework (**SEF**), which identified the key goals for the energy sector in Northern Ireland:[23] building of competitive markets, ensuring security of supply, enhancing sustainability of the energy network and developing energy

19 This is a current estimate. The I-SEM programme continues to evolve in terms of scale and scope, with costs expected to increase.

20 The average of £33.3 million – £40.8 million is £37.05 million. When added to £69 million this results in a total of £106.05 million, meaning the percentage of uncertain revenues from this combined total is approximately 35 per cent.

21 See paragraph 4.3(c).

22 KPMG1, paragraph 4.1.13 **[MC1/1/30]** defines financial headroom as the ability of a business to manage and withstand adverse shocks above the expected baseline scenario. This can be measured as the deviation tolerated in financial ratios without exceeding the actual or expected threshold required in debt covenants.

23 Department of Enterprise, Trade and Investment, *Energy: A Strategic Framework for Northern Ireland,* September 2010 (available at https://www.economy-ni.gov.uk/sites/default/files/publications/deti/sef%202010.pdf).

infrastructure. These plans extend to the period 2020. The Appellant has a very significant role to play in delivering these goals, and its role is accordingly changing and becoming more complex. Further, there are additional complexities with which the Appellant must cope due to system constraints resulting from the relatively small size of the electricity network on the island of Ireland, which means any disturbance on the system is magnified as a result.

3.31 Moreover, the Appellant's corporate status has changed significantly since 2009, and since 2014 it has been responsible for the Network Planning Function.

3.32 There are a number of significant projects (the **Significant Projects**) which the Appellant will be required to complete over the course of the Price Control Period. These include:

(a) *Large-scale pre-construction network projects (**PCNPs**)*: Following the transfer of the Network Planning Function from NIE in May 2014, the Appellant is now responsible for delivering PCNPs. The activities involved with PCNPs include reviewing and updating the network model, developing options and designs, site surveys and route selection, meeting stakeholders, conducting the statutory planning process, and all other actions leading to a fully consented project which can then proceed to the construction phase. This is a new function. It was formerly conducted by NIE. As of the date of this Appeal, the Appellant expects to invest approximately £15-20 million in total in these projects over the Price Control Period although the estimates are wide-ranging as both the projects themselves and the project pipeline is continually being re-assessed and updated. No explicit allowance is contained in the Final Determination. Currently there are four projects in the Network Planning pipeline where the forecast expenditure would exceed a materiality threshold of £1 million. The two largest are planning for the North-South Interconnector (which involves the construction of new 400kV circuit from a new substation at Turleenan, County Tyrone, in Northern Ireland, to Woodland, County Meath, in the Republic of Ireland) and the establishment of a new 110/33kV substation on the Armagh 33kV network.[24] The Utility Regulator has decided that the Appellant should be exposed to a 100 per cent cost disallowance on pre-construction costs that exceed a cap, with the further risk of financial penalties in the event of late delivery, as discussed in AS1. But, if there are cost savings or early delivery, there are no incentives or rewards. So the regulatory impact creates asymmetric risk and as the only incentive is cost management under the cap rather than choice of design or timely delivery, the Appellant is accorded potentially perverse incentives which are not ultimately in consumers' interests and may not minimise lifetime costs. The Utility Regulator has failed to take due account of the fact that the nature of pre-construction activity is inherently uncertain: locations, specifications and other important variables change over the process, sometimes as a result of national and community consultation, plans change, as they should when preferred options emerge. Moreover, the evidence of NIE and EirGrid's experience in the Republic of Ireland confirm wide variances between planned expenditure and outturn, as discussed in AS1. The method by which the Utility Regulator approached this new and important item of expenditure is a material consideration in the banks' rejection of funding to the Appellant.

[24] Further details of these large-scale PCNPs are provided at paragraphs 35-51 of RJM1.

(b) *The implementation of the Integrated Single Electricity Market (**I-SEM**):* The I-SEM is the enhanced new wholesale electricity market for the island of Ireland that will replace the current SEM. The I-SEM is described by the Utility Regulator in its Final Determination as one of the Appellant's *"key outputs"* for the Price Control Period.[25] This is due to go live in May 2018. The implementation of the I-SEM across the Republic of Ireland and Northern Ireland in 2017 will have implications in terms of the level of uncertainty faced by the Appellant because the SEM Committee's plans for detailed design and implementation work are continually evolving. The decision to invest here, its timing, and the overall design chosen, are all not within the Appellant's control. The Appellant has been working with the SEM Committee to ensure that the necessary systems and processes are in place for the I-SEM, including detailed design work streams which include the energy trading arrangements, capacity remuneration mechanism, forwards and liquidity, market power and governance and licencing. Costs for the delivery of this project therefore remain subject to a degree of uncertainty – but are currently expected to amount to £11.4 million. In its letter of 31 March 2017, the Utility Regulator suggests that costs relating to I-SEM will be ultimately be recoverable under the Dt mechanism, but subject to additional scrutiny and review. In addition, the Utility Regulator has deemed that the Appellant must bear 100 per cent of any actual capital spending on I-SEM deemed by the Utility Regulator, on an ex post basis, to be demonstrably inefficient and wasteful expenditure ("**DIWE**"). This means there is no certainty as to whether the full costs can be recovered.

(c) *The DS3 Programme:* The delivery of wider DS3 programme raises cost uncertainties owing to the need to ensure that the TSO can securely and safely operate the transmission power system with increasing amounts of variable non-synchronous renewable generation. It is also described as a *"key output"* in the Final Determination. As in respect of I-SEM, the requirements for detailed implementation of the DS3 System Services element of the programme are continually evolving and is therefore subject to some uncertainty but nevertheless the costs are expected to amount to £1.9 million in the Price Control Period (not including post-implementation costs). Once again, as with I-SEM, the Appellant is expected to bear 100 per cent of any expenditure deemed *ex post* to be DIWE.

3.33 As discussed in AS1, the changes to the Appellant's role and the Significant Projects that must be delivered means the Appellant faces an enhanced risk environment in the current Price Control Period. This has taken place against a background of pressure to deliver key strategic outputs (including the Significant Projects) during the Price Control Period in order to deliver material consumer benefits. This enhanced risk profile has been exacerbated through the Utility Regulator's approach.

3.34 Moreover, the Appellant is concerned that the proposed Price Control is also not fit for purpose to meet the scale of capital (including contingent capital) requirements expected during the Price Control. These include for example the expected increase in System Services Payments pursuant to the DS3 Programme and the introduction of new funding requirements to meet imbalances or shortfalls foreseen in respect of capital requirements post I-SEM implementation. Indeed the Appellant has identified specific risk areas of the I-SEM project where cash flow imbalance elements of revenue are envisaged and expected to be managed by the Appellant

[25] Final Determination, Executive Summary, page 3 **[NOA1/12]**.

(such as imbalance settlement, currency costs, residual error volumes and capacity remuneration mechanism). Overall, as explained in FS1, the Appellant believes that whilst it is still uncertain, it is expected to need to secure an additional £30-40 million of contingent capital, i.e. a total of approximately £60 million (three times more than in the previous period) to secure delivery of these outputs in the Price Control Period.

3.35 Part IV, Ground 2, the Revenue Uncertainty Ground, explains how an estimate of approximately 35 per cent of allowed revenues of the Appellant's revenues for the Price Control remain uncertain and is subject to intra-periodic scrutiny by the Utility Regulator and therefore cannot be regarded as certain or bankable. In previous price controls, it was not unusual for approximately 10 per cent of the Appellant's required revenues to be subject to some degree of "uncertainty" and therefore not capable of *ex-ante* allocation. The Utility Regulator's Decision leave approximately £37 million unaccounted for at the outset. This is a considerable sum in the context of an overall Price Control that provides for allowed revenues up to £69 million and is arguably more than 10 x the equity returns provided to the Appellant under the Decision.

3.36 Part IV, Ground 3, the Inadequate Allowances Ground, sets out a number of aspects of the Price Control in relation to which the Appellant has been underfunded. The regulatory framework applied by the Utility Regulator involves a significant transfer of risk to the Appellant and has inherent financeability issues. This is driven in part by the fact that the Appellant expects to bear costs for which it is not compensated in the Decision, and does not have the financial capacity to absorb these costs given the limited amount of financial headroom available. The fact that the regulatory framework does not provide for these costs exacerbates financeability problems and compromises the delivery of the Significant Projects, which is obviously not in the consumer interest.

3.37 Therefore, the Price Control results in the Appellant bearing a number of significant risks, many of which are negatively asymmetric, with no financial headroom. This is inconsistent with the Utility Regulator's own calculation of the required return based on CAPM which assumes symmetric risks in cash flows. While the Appellant accepts that it will need to bear some level of risk provided it is proportionate to the rewards on offer for outperformance, the level and nature of risk originating from the Final Determination is not appropriate for the Appellant to bear and returns are not commensurate with the level of risk attributed. Indeed, there are few examples where the Appellant can be said to be properly incentivised to achieve superior performance, as opposed to being penalised for performance which is judged, occasionally with hindsight, to fall short. There are only limited incentives in place for the Appellant to share efficiency savings or to benefit from maximising outputs, for example, any (unlikely) shortfall in network planning or non-network capex, is split 50:50 with customers. Further analysis of this increased risk environment is contained in AS1. The impact on the financeability of the SONI TSO business is explained in Part IV, Ground 1, The Financeability Methodology Ground.

(d) The Utility Regulator's procedure

3.38 Underlying the errors described in Part IV of this Notice, the consultation undertaken by the Utility Regulator in relation to the Price Control was subject to a number of procedural defects. In particular, the Utility Regulator repeatedly failed to engage with the Appellant or set out sufficient reasons in its consultations to allow the Appellant and other stakeholders to engage intelligently with its proposals and to justify its conclusions. These defects are not within the scope of this appeal but they are germane to the understanding of the sources of the many of the errors pleaded under the grounds.

3.39 The chronology of the key steps in the price control consultation process conducted is provided in Part C of BT1 and summarised in Annex I. In summary, the process started in late 2013 with discussions between the Appellant and Utility Regulatory and the provision by the Appellant on 2 February 2014 of an initial document highlighting the main issues faced by the TSO business (the **Principles and Key Issues Paper**).[26] The Utility Regulator subsequently published its Approach Paper on 9 July 2014[27] and the Draft Determination on 2 April 2015.[28]

3.40 The Appellant has engaged fully and in good faith with the Utility Regulator throughout the process and at all opportunities has sought to assist in achieving the delivery of a financeable price control on time. However, the Price Control was subject to a series of unreasonable and delays and the Utility Regulator has delayed completion of the process by 18 months without good cause. There are strong policy reasons why this should not be allowed to stand – there ought to be a disincentive for regulatory bodies to delay their decision-making.

3.41 Further, and near the last minute, the Utility Regulator has sought to backdate the Price Control arrangements for the 20 month period that will have elapsed by the time it takes effect. The Decision does so by the introduction of a “Qt” adjustment term to the formula setting the Price Control. This term was introduced to the Final Licence Modifications by the Utility Regulator without consultation contrary to the requirements under Article 14(2) of the Electricity Order, and is unnecessarily wide to achieve its intended purpose. Absent suspension of the Decision, the effect this additional licence modification has is to allow a broad and unspecified claw-back for the revenue period from 1 October 2015 relative to the position the Utility Regulator previously consulted upon and implemented. The Appellant views this as contrary to good administration. The Appellant has been left in a difficult and uncertain position regarding its revenues for far too long, through no fault of its own, and now the Utility Regulator, with no warning, is seeking to apply the formula retrospectively.

3.42 Additionally, the open-ended formal definition of “Price Control Decision Paper”[29] means that subsequent decision papers relating to the Price Control can simply be incorporated by reference to the TSO Licence on an ongoing basis, without the need to implement any associated licence modifications and without offering the Appellant any opportunity to appeal such decision. The Appellant believes this is an unprecedented measure in UK regulation.

3.43 A number of the conditions in the Final Licence Modifications, which are not referenced within the Final Determination, have a material effect on the financial position of the Appellant and on its ability to deliver its regulated activities, and cannot be considered permissible as “*incidental or consequential*” modifications under Article 14A(3) of the Electricity Order.[30] In the Appellant’s

26 Principles and Key Issues Paper [**NOA1/8**]

27 Utility Regulator, “*Approach Paper to the Price Control for Electricity System Operator for Northern Ireland (SONI)*”, 9 July 2014 [**NOA1/9**].

28 Utility Regulator, “*Draft Determination to the Price Control 2015-2020 for the Electricity System Operator for Northern Ireland (SONI)*”, 2 April 2015 **[NOA1/11]**.

29 Which, the Appellant notes incorrectly refers to the Decision Paper as having been published on 10 March 2017 whereas in fact the Decision for the TSO Licence was published on 14 March 2017.

30 This includes, for example, amendments to the incentive arrangements in respect of Dispatch Balancing Costs proposed in paragraph 2.2(f) of Annex 1.

view, the requirement in Article 14(2) of the Electricity Order that the Utility Regulator give notice setting out the proposed modifications and their effect has not been met in respect of these modifications.[31]

4 Grounds of appeal

(a) Overview

4.1 The Appellant brings this appeal because the Decision is marked by a number of serious errors which have the effect of rendering the Appellant unfinanceable under the Price Control. The Appellant contends that the Decision is therefore in breach of the Utility Regulator's Principal Objective to protect the interests of consumers of electricity in Northern Ireland (under Article 12(1) of the Energy Order). This Principal Objective is not discharged unless the Utility Regulator fulfils its Financeability Duty (imposed by under Article 12(2) of the Energy Order) by securing that the Appellant, as the holder of the TSO Licence, is able to finance its regulated activities.

4.2 The Appellant believes it is left with no option but to bring this appeal given the errors in the Decision, the Final Determination and the approach taken by the Utility Regulator in setting the Price Control. Absent correction by the CMA, the proposed Price Control fails to secure the financeability of the SONI TSO business. Therefore, the Appellant respectfully requests that the CMA find the errors set out in Part IV below and consider the remedies proposed by the Appellant in Part V of this Notice – as summarised below.

(b) Summary explanation of grounds

4.3 The specific grounds and underlying errors on which the Appellant brings this Appeal are explained in detail in Part IV of this Notice. By way of preliminary explanation, there are three grounds, as follows:

(a) The Utility Regulator's failure to secure the Appellant's financeability as an inevitable consequence of its failure to conduct a proper assessment. It should not have been satisfied by applying a series of financial ratio tests or by using a methodology which is not fit for purpose for a business of the Appellant's type. This approach, and the Utility Regulator's Decision overall, did not provide for adequate revenues or remunerate the Appellant for the capital employed given the risks it faces. In this Notice this ground is referred to as "**Ground 1: the Financeability Methodology Ground**".

(b) The Utility Regulator's failure to secure the Appellant's financeability by failing to ensure that adequate arrangements were put in place to deal with the significantly uncertainties that the Appellant faces during the Price Control Period. In particular, over 35 per cent of revenues remain uncertain. This has created uncertainty that revenues will not be secured for the Appellant to fulfil its functions and licence obligations which has in turn affected the Appellant's ability to secure finance from investors. This is accompanied by the complete absence of any right of appeal and duty to amend or correct. In this Notice this ground is referred to as **"Ground 2: the Revenue Uncertainty Ground**".

[31] As explained in Part IV of this Notice, such modifications failed to achieve the effect stated by the Utility Regulator in the Final Determination, and therefore fall within the ground of appeal set out in Article 14D(4)(d) of the Electricity Order.

(c) The failure by the Utility Regulator to secure the Appellant's financeability by the unjustified disallowance or neglect of certain specific costs which the Appellant is required to incur to fulfil its functions and Licence obligations. In this Notice this ground is referred to as **"Ground 3: the Inadequate Allowances Ground**".

4.4 The errors identified under each of these grounds have the effect that the Utility Regulator has failed to secure the Appellant's financeability for the Price Control Period and as such the Decision is in breach of its Financeability Duty. The correction of the errors in the Utility Regulator's Decision is required to secure the Appellant's financeability and will ensure that significant benefits are delivered to consumers of electricity in Northern Ireland.

4.5 Each of the Grounds and the 11 errors are set out below, and summarised in Annex II.

(i) Ground 1: the Financeability Methodology Ground

4.6 Central to this appeal is the Appellant's contention, supported by evidence from its capital providers and independent expert analysis, that the Utility Regulator has failed to provide a price control that can secure financeability of the Appellant to fulfil its obligations and deliver the outputs required under the licence and detailed in its Business Plan. This is a free-standing claim and applies even assuming correction of the errors detailed below under the Revenue Uncertainty Ground and the Inadequate Allowances Ground.

4.7 In doing so the Decision is compromised by three particular errors, as detailed in Part IV of this Notice.

(A) Error 1(a): Failure to adopt a price control framework that could secure the Appellant's financeability

4.8 The Utility Regulator has erred in failing to use a framework for the design of the Price Control that could secure the Appellant's financeability. As a result, the Utility Regulator's approach to assessing the financeability of the Appellant under the Price Control was inadequate with the inevitable result that the Appellant was not financeable.

4.9 Such a framework should reflect the asset-light nature of the Appellant, its high operating costs relative to its limited balance sheet, high operational gearing, small financial buffer compared to the scale of its operations, and its risk profile.

4.10 Rather than adopt a more appropriate framework, the Utility Regulator has rolled forward the capital maintenance model (based on RAB*WACC) that was applied when the TSO function was integrated under the ownership of NIE, the transmission and distribution asset owner, and which is typically applied to asset-heavy utilities.

4.11 The changing responsibilities of the Appellant and increasingly challenging environment it faces in the new Price Control Period means a different regulatory model and remuneration structure should have been adopted. This alternative model would have regard to the scale and nature of capital employed in the Appellant's TSO business relative to its operating costs and the significant operational risks that the Appellant faces in fulfilling its TSO licence obligations, for example from the transmission network planning function that was inherited from NIE and the substantial changes in the operation and balancing of the electricity system in Northern Ireland that will occur due to significant projects such as I-SEM and DS3 in the Price Control Period.

4.12 The Appellant's submissions on this error are supported by expert evidence from KPMG[32] and Europe Economics.[33]

(B) Error 1(b): Errors in the Utility Regulator's limited assessment

4.13 Even assuming that a WACC*RAB framework could be manipulated to ensure sufficient revenues for the Appellant's business to be financeable across the Price Control Period, the methodology employed by the Utility Regulator to assess this was inadequate to reach this conclusion. This is because it was compromised by a number of errors and included insufficient analysis for the Utility Regulator to form a view that the Appellant would have sufficient remuneration to meet its Licence obligations and deliver the expected outputs under the Utility Regulator's chosen framework. Further, the Utility Regulator did not at any stage provide an explanation of the nature of the financeability tests it conducted – it failed to provide any interpretation of the results from the limited financial metrics it applied (alongside other factors such as liquidity) or to explain the rationale for the metrics its used, and it did not specify the thresholds at which the Appellant would be deemed not financeable. In the case of a business like SONI an assessment of "securing" financeability cannot be conflated with the conduct of "simple" financial ratio tests. From this, the Utility Regulator could not have concluded that the Appellant was financeable under the proposed Price Control and therefore should not have been satisfied that it had discharged its Financeability Duty. KPMG, which was instructed to provide an expert opinion as to the adequacy of the Utility Regulator's financeability assessment, have also concluded that "*the UR does not appear to have undertaken a sufficiently thorough assessment to conclude that the FD will allow SONI to finance its activities on a stand-alone basis*".[34]

4.14 The Utility Regulator made three particular sub-errors in this regard.

4.15 Firstly, the Utility Regulator failed to remunerate all layers of capital within the business by not funding the Appellant for the cost of the Parent Company Guarantee (**PCG**) which it is required by Licence to maintain or the debt guarantee that EirGrid is required to provide to the Appellant's lenders. The Utility Regulator refused to remunerate the PCG on the false conclusion that it is remunerated under a separate parent company guarantee given under the SEMO Licence, albeit for the distinct risks associated with that licence and not the risks under the TSO licence.

4.16 Secondly, the financeability cross-checks carried out by the Utility Regulator were fundamentally flawed. Specifically, the Utility Regulator failed to employ a proper methodology in line with good regulatory practice, instead putting undue weight on past performance and conducting a limited and inadequate financeability assessment that focused on a narrow set of metrics and include inadequate consideration of downside outcomes. The Utility Regulator failed to properly consider equity financeability, engaging only in a consideration of debt metrics.

4.17 This assessment of the Utility Regulator's performance is supported by expert analysis by KPMG, who note that "[*t]he financial model used by the Regulator does not reflect the*

32 KPMG1 **[MC1/1/2-128]**.

33 AL1, paragraphs 8.1-10.5.

34 KPMG1, paragraph 1.25 **[MC1/1/ 6]**.

projections set out in the FD and there are also some inconsistencies within the model itself".[35] In particular, in addition to making errors in the limited debt tests it applied, the Utility Regulator ignored entirely the question of equity financeability, despite the premise in its analysis that the Appellant could be 100 per cent equity funded. The scope of its errors in relation merely to its inadequate debt financeability assessment is such that, if the correct benchmarks had been used to compare these results, the Utility Regulator would have concluded that the minimum financial ratios were not met and most likely that remedial action was required.

4.18 Thirdly, KPMG has noted "*other issues with the UR's financial model which render its financeability analysis not robust and most likely biased*".[36] In particular, KPMG notes that *"positive incentive payments"* are assumed to form part of the base case for the Utility Regulator's financeability assessment with the consequence that the revenue – and therefore the financial headroom – are assumed to be higher than expected in the base case. This means that the financial ratios are artificially inflated and cannot, the Appellant submits, be relied upon as evidence to form a robust conclusion as to its financeability.

(C) Error 1(c): Failure to undertake a complete assessment

4.19 The Utility Regulator's assessment of financeability in the Final Determination is incomplete and inadequate, in particular in relation to equity financeability. Although certain metrics are quoted, the Utility Regulator does not explain how it is satisfied that equity holders will be able to earn a reasonable return in the future (assuming efficient operations). When a financeability assessment is carried out consistent with what would be expected of good regulatory practice for asset-light utility companies as well as metrics and analysis techniques used by credit agencies and lenders, it is clear that the Utility Regulator's approach is not capable of securing the standalone financeability of the Appellant.

4.20 The Appellant's case is that it is thoroughly inappropriate to employ a methodology used for asset-heavy utilities, with significant tangible assets, by seeking to assess financeability solely through the application of financial ratios in respect of RAB capital and RAB investment. The Appellant is not financeable without external financial support and the chosen regulatory framework does not provide the clarity that capital providers require before advancing funds. This is partly because not all layers of capital in the business are actually remunerated and, measured by conventional debt metrics, returns are unstable, so further deterring sources of funds.

4.21 When financeability is tested using an approach and metrics which are appropriate to this type of business, that is, by applying margins which reflect the scale and nature of the Appellant's operations, it is clear that the business will not earn the profits which investors would require before advancing capital, and hence it is not financeable. Specifically, when the WACC*RAB framework is compared to a benchmarked EBIT of 11 per cent of controllable costs, (which KPMG advises is an appropriate level), the Appellant's investors are subject to a shortfall of £5.3 million under the Decision.

4.22 Finally, considering the above, it is equally clear that the business has very limited financial headroom or buffer so that its capacity to withstand shocks or mange financial risks to which it

[35] KPMG1, paragraph 7.4.2 **[MC1/1/page 66]**.

[36] KPMG1, paragraph 7.4.4 **[MC1/1/page 66]**.

might be exposed, is very limited. This absence of financial resilience further adds evidence to the finding that the Utility Regulator has failed to secure the Appellant's financeability.

4.23 This constitutes a summary of the Appellant's evidence based upon its analysis of the business and its interaction with prospective lenders and its parent. In addition, the Appellant instructed KPMG to conduct its own thorough financeability assessment applying the tests the Utility Regulator should have conducted but failed to do so. KPMG finds that: [37]

> *[m]etrics used for asset-light businesses such as EBIT margins suggest that SONI does not have a sufficient remuneration for all sources of its capital under the FD.*

4.24 KPMG goes on to conclude that: [38]

> *[i]n the absence of [adequate limitations on risk exposure], and given that SONI does not meet the required thresholds for metrics used for asset-light businesses, SONI is unlikely to be financeable from debt perspective.*

4.25 KPMG confirmed the Appellant's analysis that the Utility Regulator had failed to verify that the Final Determination enabled the Appellant to earn expected equity returns commensurate with its required returns. They confirmed that no assessment of returns on equity or on capital employed was conducted by the Utility Regulator despite its findings that the Appellant could feasibly be 100 per cent equity financed and the importance placed on the CMA's analysis of profitability in the recent energy supply market investigation where the CMA noted the importance of Return on Capital Employed metrics.[39] KPMG conducted its own analysis of return metrics and found that based on the evidence in respect of the risks to which the Appellant is exposed: [40]

> *In the case of SONI, the expected return falls below the allowed return. To the extent that the resulting shortfall is material, this will pose a significant challenge for equity financeability.*

4.26 This means there is a significant shortfall in the expected returns that investors would expect to earn and that the Appellant is unfinanceable from an equity perspective. This is particularly the case given the thinness of the business and its balance sheet, by contrast with the revenues that it handles or influences.

4.27 In AS1, Aidan Skelly identifies the key risks which are expected to materialise over the Price Control Period. One of the principal sources of risk exposure to the Appellant over the Price Control is likely to be network project planning expenditure. This is supported by an expert report from Jacobs, the engineering consultancy firm.[41] Liquidity risk and revenue cap risk can result in a significant negative impact on equity returns in the event they materialise. Based on

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37 KPMG 1, paragraph 7.14.5 **[MC1/1/page 88]**.

38 KPMG 1, paragraph 7.14.5 **[MC1/1/page 88]**.

39 Final Determination, paragraph 275 **[NOA1/12]**.

40 KPMG3, paragraph 1.41.1 **[MC2/1/6]**.

41 Sections 2-7 of Jacobs Report **[JM1/1/Pages 3–20]**.

the evidence provided to it by the Appellant, KPMG concludes that the Appellant is exposed to a level of risk that is: [42]

> *inconsistent with the assumptions typically used by UK regulators with respect to the risk tolerance of asset-heavy utilities*…[which]…,*suggests that […] the FD exposes SONI to a level of risk that makes it not financeable".*

4.28 Finally, on the Utility Regulator's assessment of financial resilience, this analysis, to ensure there is sufficient headroom under the Price Control to accommodate plausible downside shocks without jeopardising the company's ability to raise finance in the future, is particularly important for the Appellant where the consequences to consumers of a TSO business that cannot finance its activities are not merely delays to long term infrastructure but, manifestly more immediately, as an inability to meet weekly market settlements or to deliver market and other systems changes to meet public policy objectives and requirements. As demonstrated by the Appellant's own analysis and drawing on KPMG's analysis, had the Utility Regulator tested financial resilience it would have found that the Appellant is highly sensitive to plausible downside shocks which would pose a significant challenge from both debt and equity perspectives and negatively affect its ability to raise financing.

4.29 In sum, the Utility Regulator has neither applied a regulatory model well suited to secure the Appellant's financeability nor has it assessed its financeability to an appropriate standard. If it had, it would have concluded that the Price Control does not provide for the Appellant's financeability on any reasonable measure that takes into account its particular characteristics.

(ii) <u>Ground 2: the Revenue Uncertainty Ground</u>

4.30 The Decision is also vitiated by an inappropriate approach to uncertainty during the Price Control, which poses the risk that the Appellant may not recover significant costs in relation to Price Control outputs which would have an important bearing on financeability. This is because the Utility Regulator has determined that a very significant proportion of the revenues will be subsequently determined either under a general "Dt" mechanism (originally designed to facilitate recovery of "unforeseen" or pass-through costs) or through an as-yet-unspecified process. This exacerbates the Appellant's precarious financial position by shifting costs that apply to what the Utility Regulator acknowledges are key required outputs from the Price Control at its inception to be dealt with by irregular intra-periodic review and *ex post* assessment without assurances as to full recovery through tariffs or any check on the regulator's discretion. As noted above, the Decision leaves approximately £37 million unaccounted for over the Price Control Period, leaving aside any unforeseen funding requirements, in the context of an overall Price Control settlement of £69 million (some 35 per cent of allowed revenues).

4.31 The Decision includes seven specific errors as detailed in Part IV of this Notice.

(A) Error 2: Failure to provide a cost recovery mechanism for PCNPs

4.32 There is no guarantee in the Licence or elsewhere to ensure that the Appellant will recover the costs of planning for PCNPs – a new role that the Appellant acquired in 2014, which it currently believes will amount to £15-20 million over the Price Control Period. The Decision fails to

[42] KPMG3, paragraph 5.8.36 **[MC2/1/39]**.

provide a means for such cost recovery under the Licence (save for the costs of any abandoned projects which are to be recovered under the Dt mechanism, subject to assessment against efficient costs and an ex ante cap), meaning there is no certainty that the Appellant will recover its costs at all or in a timely manner to be able to satisfy lenders' requirements before providing financing. Given the magnitude of the revenues at stake the Utility Regulator cannot be said to have discharged its Financeability Duty to secure that the Appellant can finance its activities. Nor can the scheme as adopted offer any incentive to superior performance; it offers only the threat of adverse consequences of falling short of the Utility Regulator's subsequent cost stipulation.

(B) Error 3: Failure to provide a cost recovery mechanism for additional IS capital investment

4.33 A considerable element of the Appellant's costs (£8.927 million in the Business Plan) relate to information system capital investments. Under previous price controls, there was provision for such costs to be recovered under the Dt mechanism. The Decision removes this option but fails to provide an alternative. To the extent any unforeseen requirements for IS Capex outputs arise, the Utility Regulator has determined that the Appellant should be exposed to bearing 100 per cent of these costs, regardless of how material these unexpected costs might be. Given the dependency of the Appellant's business on information systems and the evolving systems requirements, this raises significant uncertainties for the Appellant in terms of its ability to absorb any additional costs associated with these outputs. The failure to identify an appropriate mechanism for the recovery of costs in relation to unforeseen IS Capex outputs could therefore have material adverse consequences for the Appellant's financeability and heightens investment risk given the lack of transparency of the Appellant's financeability.

(C) Error 4: Failure to provide a suitable cost recovery mechanism for Significant Projects

4.34 The Dt mechanism existed in the Licence prior to the Price Control, but its use was restricted to the recovery, ex post, of "unpredictable costs". In the Decision, the Utility Regulator has materially changed the application of Dt. This represents a change of policy. In particular, the Utility Regulator has chosen to direct that the costs of certain Significant Projects, namely I-SEM and DS3 (and any PCNPs that are abandoned), should be recovered via the Dt mechanism rather than providing an up-front allowance and/or allowing a re-opener. The Utility Regulator's approach is not in line with good regulatory practice, as explained in the expert report provided by CEPA.[43] It is not evident what consideration, if any, the Utility Regulator gave to employing alternative uncertainty mechanisms that would be better suited to dealing with such considerable sums, and which would be less detrimental for the Appellant's financeability. The effect of this approach is exacerbated by the definition of "Price Control Decision Paper" within the Licence, which in effect permits the Utility Regulator, simply by publishing further decision papers, to radically alter the expectations of all parties as to the use of Dt in future.

(D) Error 5: Failure to provide a suitable right of appeal concerning decisions regarding cost recovery for Significant Projects

4.35 Where revenues are claimed and assessed under the Dt mechanism this involves a bilateral process between the Utility Regulator and the Appellant, resulting in an adjustment to the total annual revenue cap. It does not give rise to a need to modify the TSO Licence, meaning that

43 CEPA Report, paragraph 5.1 **[IA1/1/40-42]**.

there is no right for the Appellant or third parties to appeal the decision to the CMA contrary to the intent of the legislation. As such, a significant element of expenditure is reserved for the regulator, and abstracted from review by the CMA. The lack of appeal rights for such material funding decisions takes away an important safeguard valued by sources of finance. Where funding decisions relate to materially significant and complex projects, described in this Notice as “Significant Projects” and identified as projects where the costs exceed £1 million, an interim review with the accompanying licence modification consultation is a more appropriate mechanism to employ.

(E) Error 6: Failure to manage uncertainty by creating additional uncertainty through implementing an unworkable uncertainty mechanism

4.36 The Utility Regulator has introduced a two-stage process into the existing Dt mechanism whereby the Appellant must submit Dt claims for pre-approval up to a cap and must later report the actual costs which are then subject to an adjustment mechanism. The result is unworkable. The Dt mechanism was designed to facilitate recovery of unforeseen costs or costs which cannot be accurately calculated. Its expansion to embrace costs which are foreseen but not approved is likely to result in delay and extra cost, and creates downside-only risk for the Appellant, the extent of which cannot be quantified in advance. The Utility Regulator has indicated that this process will also apply to PCNPs, although the process in respect of PCNPs is somewhat unclear.

(F) Error 7: Unjustified creation of uncertainty through failure to provide guidance on the application of DIWE

4.37 The Utility Regulator has introduced a mechanism permitting it to disallow recovery of costs from the Appellant where it deems the expenditure was inefficient or wasteful. No guidance on the application of this term has been forthcoming. The Utility Regulator has reneged on its initial indications that guidance would be published “in due course”. In the context of a Price Control that is already materially underfunded, the threat of the Utility Regulator exercising this provision to introduce further cuts, without guidance, materially heightens the Appellant’s risk profile. This is highly unsatisfactory. Without guidance on this principle, the Appellant is not able to forecast with any certainty its worst-case scenario costs or the actions the Utility Regulator might propose to take. In order to secure funding from potential lenders, the Appellant needs to be able to present such lenders with guidance from the Utility Regulator so that the lenders can assess the Appellant’s creditworthiness and authorise lending.

(G) Error 8: Unjustified creation of uncertainty through the introduction of the Qt adjustment

4.38 At the final stage of the Price Control Process, the Utility Regulator introduced a “Qt” adjustment to the Price Control formula, which is unnecessarily broad in scope, and set out its intent to back date the Price Control and the associated Final Licence Modifications on a retrospective basis to 1 October 2015. Both aspects were introduced without engaging in any consultation. The application of this adjustment is unclear, given that there is no limit on the scope of the adjustments that can be applied to the maximum revenue cap for the year ending 30 September 2017. The Decision promises guidance as to how this term is to operate, but this has not been forthcoming. As a consequence the Appellant has no certainty as to how the provision will be applied.

4.39 This failure to create an adequate set of arrangements for managing uncertainty in the Price Control means that the Appellant, its shareholders and its lenders do not have any visibility over significant portions of revenue. The Appellant acknowledges that it faces greater challenges and changes in the period up until 2020 as compared with previous price controls. But this only points to the Utility Regulator having to do more to manage uncertainty to secure the Appellant's financeability, not less. The Utility Regulator's failure to tailor its approach to uncertainty so as to minimise the financial risks directly affects the Appellant's financeability, in particular its ability to raise finance. There is no evidence that the Utility Regulator has factored the impact of these arrangements into its financeability assessment and the Appellant was not provided with any information to suggest what scenarios the Utility Regulator had considered.[44]

4.40 The inadequacy of the Decision in relation to uncertainty is exacerbated by the Utility Regulator's failure to include any detailed, coherent or consistent explanation in the consultation documents or in the Final Determination concerning its approach to managing uncertainty and its reasoning, and its failure to consider and/or adopt alternative approaches.

(iii) <u>Ground 3: the Inadequate Allowances Ground</u>

4.41 This Ground concerns the unjustified failure by the Utility Regulator to provide certain specific allowances to the Appellant. The Utility Regulator has made a number of clear errors concerning allowances which result in known costs being subject to non- or under-recovery across the Price Control Period, including costs which the Appellant is legally obliged to incur at known higher rates that arise from the transfer of the transmission network planning function from NIE.

4.42 While superficially the Utility Regulator may be said to have increased some allowances to the Appellant, it should be understood that on a like-for-like comparison, and when the DIWE challenge is factored in, it is by no means certain that allowances will have increased. It is the Appellant's view that, given its new responsibilities as compared to the last review, the allowances are inadequate for it to discharge its functions and licence. These are material errors in the Final Determination which must be corrected, independently of the errors stated under the two grounds above. These errors are not cured by the statements in the Decision that the Utility Regulatory intends to consult further to reconsider some of the decisions that it has already locked in, or that it will consider a Dt submission at a later point in time, but after the costs have been incurred. None of this will satisfy providers of capital.

4.43 The errors concerns three categories of allowances.

(A) Error 9: Failure to provide adequate payroll allowances for network planning staff

4.44 The Utility Regulator has failed to provide the Appellant with adequate payroll allowances in respect of persons transferred from NIE in connection with the transfer of the network planning function in 2014. This is in breach of the Appellant's legitimate expectation that it would be funded in full for these costs, and in disregard of the application of relevant legal obligations inherited by the Appellant under the applicable transfer of undertakings (protection of employment) regulations. The Appellant cannot reasonably be expected to reduce these costs owing to its legal legacy obligations and the Appellant believed this was understood by the Utility Regulator.

[44] Following publication of the Decision, the Appellant submitted a request for the Utility Regulator to provide this information under the Freedom of Information Act 2000. A response is due on or before 13 April 2017 as explained further in paragraph 121 of BT1.

(B) Error 10: Failure to provide adequate pensions allowances

4.45 The Utility Regulator has failed to provide the Appellant with adequate pensions allowances, by taking a decision to fund the Appellant for significantly less than the full costs of its contributions to its defined benefit scheme (including legally inherited costs from the transfer of the network planning function). This risks creating a significant funding deficit for the current Price Control Period and beyond. The attendant risk to the Appellant's financeability is compounded by the Utility Regulator's decision to consult further on a new approach to pension deficit recovery which would require the Appellant to fund all such deficit costs for the Price Control and beyond.

(C) Error 11: Failure to provide an adequate IS capital expenditure allowance

4.46 The Utility Regulator has failed to provide adequate information systems (IS) capital expenditure allowances, by failing to fund an entire area of the Appellant's IS Capex submission (DS3/Smart Grids) on the mistaken assumption that this area was outside the scope of the Price Control, and should have been discharged by the Utility Regulator's SEM Committee, and by failing to correct a clear error in its adjustments for inflation. This error threaten the ability of the Appellant to deliver one of the two significant regulatory projects referred to above, which when implemented is expected to provide significant benefits for consumers in Northern Ireland.

<u>Summary</u>

4.47 The cumulative impact of all these Errors 1 – 11 is that, absent correction by the CMA, the Appellant is required to find additional funding to the value of £14.7 million to meet its obligations. Given this deficit, it is evident that the Utility Regulator has failed to secure the Appellant's ability to finance its activities under the Price Control. As explained by Aidan Skelly:[45]

> *SONI has not been able to secure financing from debt or equity providers based on the Utility Regulator's decision. The principal reason for lack of access to the required capital is that the levels of remuneration contained in the Final Determination do not provide enough of a buffer either for lenders to be confident that SONI will be able to service its debt liabilities; or for its equity holders to be confident that they will be able to achieve returns commensurate with the risks that SONI faces.*

(c) Focus of this appeal

4.48 In bringing this appeal, the Appellant has been conscious of the overriding objective that the CMA should dispose of appeals fairly and efficiently within the time periods prescribed by the Electricity Order and that the Appellant should assist the CMA to further this objective.[46] The Appellant will assist the CMA in seeking to narrow the issues and points in dispute during the course of the appeal.[47]

4.49 This Notice addresses only the most salient issues concerning the Price Control, which are individually – and collectively – of material importance to the Appellant's financeability and

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[45] Paragraph 105, AS1 **[AS1/1]**

[46] Competition Commission, *Energy Licence Modification Appeals Rules*, September 2012, paragraph 4.1.

[47] Competition Commission, *Energy Licence Modification Appeals: Competition Commission Guide*, September 2012, paragraph 3.5.

where the errors made by the Utility Regulator are very clear. The Appellant believes that the Utility Regulator's decision on the Price Control was deficient in a number of other respects but these are not included. This includes a failure properly to take into account the innovation fund proposed by the Appellant in its original submission, and an erroneous salary benchmarking exercise conducted by the Utility Regulator, which was neither evidence-based nor appropriate.[48]

4.50 The Appellant also has significant concerns regarding the procedure followed by the Utility Regulator in its consultation leading to its Price Control determination. The Appellant draws attention to some of these concerns in the context of the grounds detailed in Part IV of this Notice but they are not pleaded as separate errors.

5 Relief sought

5.1 The Appellant seeks permission to appeal the Utility Regulator's Decision.

5.2 The errors set out in this Notice are specific but also interlinked and collectively result in the conclusion that Utility Regulator has not discharged its Financeability Duty.

5.3 For the reasons set out in this Notice, the Appellant requests that the CMA remedy the errors summarised in Part IV in the following manner, as more fully set out in Part V of this Notice:

(a) in the first instance, by quashing the Decision and substituting its own decision in correction of the errors which secures the Appellant's financeability by giving effect to an appropriate price control design framework for the Appellant and addressing the errors in respect of the inadequate allowances and the inadequate approach to uncertainty; or

(b) in the alternative, by quashing those aspects of the Decision it finds in error and substituting its own decision to the extent necessary to remedy each error identified in this Notice; and

(c) by awarding the Appellant its costs in respect of bringing this appeal.

5.4 The specific remedies which the Appellant requests the CMA order are set out in detail in Part V of this Notice. These are intended to address operational and/or financial risk and serve the interest of Northern Ireland consumers by ensuring the TSO business can deliver its regulated outputs in accordance with its licence obligations and duties across the Price Control Period. The remedies equate to provision of financial allowances of £13.2 million in combination with the remedies and reliefs in respect of uncertainty and risk.[49]

5.5 As a consequence of considering the remedies requested by the Appellant, it cannot be assumed that the correction of the errors under one of the grounds will cure the financeability problem identified in this Notice and supporting evidence. For example, remedies that address the errors identified in the Inadequate Allowances Ground will not cure the financeability problems caused by the Decision Error Ground or the Inadequate Uncertainty Mechanisms

[48] Further discussion of this benchmarking exercise is at paragraphs 79-80 and 164-170 of BT1.

[49] The difference between the shortfall in funding of £14.7 million and the £13.2 million stated here is the £1.5 million associated with the expected loss in respect of costs where the Appellant has been accorded an asymmetric risk profile. This is further set out in AS1.

Ground and, equally, corrections of the errors under the Inadequate Uncertainty Mechanisms Ground cannot cure the lack of sufficient allowances for known costs the Appellant was legally obliged to incur.

5.6 In this regard, the CMA's assessment of whether the Appellant's business is financeable under the remedies chosen must recognise that "financeability" is much wider than measuring against metrics (the traditional consideration of financeability by regulators for asset heavy utilities) but must also assess the effects of the treatment of significant costs subject to uncertainties and the ability of the Decision to provide sufficient certainty regarding treatments or risk for lenders and investors to be willing to finance the delivery of expected outputs in the interests of consumers. The fact that some improvements could be made to ensure that a TSO business has acceptable financial ratios will not guarantee that outputs can be delivered across a Price Control Period where some 35 per cent of its revenues are outside of its control due to *ex ante* assessment without a right of appeal.

6 Key documents

6.1 The grounds of appeal are contained in this Notice. The Appellant has provided supporting evidence for this appeal in Exhibit NOA1 and in the Witness Statements and Exhibits to those Witness Statements.

6.2 The Appellant has provided the following witness statements in support of its appeal:

(a) First Witness Statement of Bill Thompson, Group Regulation Manager of EirGrid Group;

(b) First Witness Statement of Aidan Skelly, Director of Finance and Legal of EirGrid Group;

(c) First Witness Statement of Fintan Slye, Chief Executive of EirGrid Group;

(d) First Witness Statement of Robin McCormick, Director of Operations, Planning and Innovation for the EirGrid Group and General Manager of SONI Limited;

(e) Expert Witness Statement of Dr Maciej Firla-Cuchra, Partner, KPMG LLP;

(f) Joint Expert Witness Statement of Dr Maciej Firla-Cuchra, Partner, KPMG LLP and Michael Smart, Associate Director, KPMG LLP;

(g) Expert Witness Statement of Mr James Saunders, Principal, Punter Southall Limited;

(h) Expert Witness Statement of Dr Andrew Lilico, Executive Director, Europe Economics;

(i) Expert Witness Statement of Ian Alexander, Director, Cambridge Economic Policy Associates Ltd; and

(j) Expert Witness Statement of Joanne Moran, Divisional Director, Jacobs UK Limited.

6.3 The Appellant exhibits the following key documents of the Price Control in Exhibit NOA1 to this Notice:

(a) the Final Determination;[50]

(b) the Utility Regulator's Financial Model;[51]

(c) the Final Licence Modifications;[52] and

(d) the Decision Paper.[53]

6.4 Other documents relevant to the Price Control include:

(a) the Principles and Key Issues Paper;[54]

(b) the Approach Paper;[55]

(c) the Business Plan;[56]

(d) the Draft Determination;[57]

(e) SONI's full response to the Draft Determination (18 May 2015);[58]

(f) The Utility Regulator's proposed licence modifications *to* Annex 1 of the *"Licence to Participate in the Transmission of Electricity granted to SONI Limited*" dated24 February 2016 (the **Draft Licence Modifications**);[59] and

(g) SONI's full response to the Draft Licence Modifications and annex to response (23 March 2016).[60]

6.5 The Appellant has endeavoured to provide the CMA with all relevant facts, documentary evidence and witness statements with this Notice. If permission to appeal is granted, it may be necessary for the Appellant to submit further material, particularly following receipt of the Utility Regulator's response and any disclosures made therein or subsequently in the CMA's process.

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50 **[NOA1/12]**.

51 **[NOA1/14]**.

52 **[NOA1/17]**.

53 **[NOA1/18]**.

54 **[NOA1/8]**.

55 **[NOA1/9]**.

56 **[BT1/31]**.

57 **[NOA1/11]**.

58 **[BT1/40]**.

59 **[NOA1/13]**.

60 **[RJM1/2].**

7 Contact details

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PART II

SUMMARY OF PRICE CONTROL FORMULA

8 Overview

8.1 The price control formula is found at paragraph 2 to Schedule 1 to the modified TSO Licence. In any year the Appellant is subject to an annual revenue cap denoted by MTSOt. A summary of the components of the formula is provided below:[61]

$$M_{TSOt} = A_{TSOt} + B_{TSOt} - BI_t + D_{TSOt} + Q_t + K_{TSOt} + INCENT_t$$

8.2 The regulated SSS/TUoS revenue is set not to exceed the regulated maximum revenue, as set out in paragraph 2(2) plus an amount in respect of the Moyle Interconnector.

8.3 The maximum "core" SSS/TUoS revenue is set by reference to the formula. The first term ATSOt means the aggregate of the Appellant's costs of System Support Services for each year plus disbursements to the owner of the transmission business for transmission services and to the transmission system operator business. The Appellant views this element as essentially including those costs which are agreed as being 'uncontrollable'.

8.4 The BTSOt is the amount equal to that allowed by the Utility Regulator for cost categories listed in Table A in paragraph 2.2(b)(vi) and the allowed rate of return, in each case indexed annually by reference to the RPI. From this is deducted the BIt - a sum equal to 50% of the outperformance or underperformance of the Appellant against the allowed BTSOt. In essence the Appellant understands the intent to be that where the Appellant's actual costs exceed those allowed, the Appellant will be responsible for 50 per cent and where actual costs are lower than those allowed the Appellant will receive 50 per cent. However this is not wholly straightforward as the rate of return is also included in the calculation. In addition, whatever sum considered by the Utility Regulator to have been incurred demonstrably inefficiently or wastefully (DIWE) is deducted prior to the apportionment.

8.5 Provision is made at DTSOt for change in law and excluded SSS/TUoS costs. This is the mechanism for the advance approval of certain expenditure, subject to a de minimis threshold, for certain substantial categories of expenditure which have not been accorded a value in the Price Control and associated licence modifications. Absent approval the expenditure will not be allowed to be recovered in tariffs for the year in question. This is the Dt procedure much discussed in the evidence. It includes provision for pension costs (paragraph 8(1)(d)), Network Planning (where projects do not proceed to construction) (paragraph 8(1)(h)) and "any other reasonable and efficient costs" incurred by the TSO (paragraph 8(1)(i) amongst others).

8.6 The QTSOt term is a new addition to the maximum revenue formula. This mechanism was not specifically included in either the Price Control or Licence modifications consultation process. This seeks to adjust the maximum revenue by an adjustment determined by the Utility Regulator in the relevant year ending September 2017, the second year of the Price Control,

61 As further described by the Utility Regulator in paragraph 11 of the Final Determination **[NOA1/12]**.

and notified to the Appellant. In the Decision, it is stated that the mechanism is designed to ensure the maximum revenue for the first year of the Price Control is calculated on the basis of the Price Control. However, the scope of application of the Qt term is not clear in the Licence itself.

8.7 KTSOt is the correction mechanism applied to the maximum revenues for a relevant year as per its end of year position and includes provision for compensation for interest at LIBOR + 2 per cent. Notably it does not capture any interest or other financing costs associated with any intra-year positions. This is also the mechanism where the Utility Regulator intends to apply deductions to revenues, via the ADTSOt adjustment sum, to account for when the actual cost of any individual DTSOt component *ex post* is lower than the initial *ex ante* approved allowance. This is in addition to the DIWE and 50:50 apportionment mechanisms referred to above, however, as it does not provide for an adjustment sum in the event of actual costs being higher than previously allowed for, the mechanism imposes a substantial asymmetric downside risk onto the Appellant.

8.8 The INCENTt allows for any incentive payments or penalties regarding the Dispatch Balancing Costs incentive to be incorporated into the maximum revenue formula of the Appellant for a relevant year.

PART III

LEGAL PRINCIPLES

9 Overview

9.1 In this Part of the Notice, the Appellant identifies the legal principles relevant to this appeal, which is brought under the Electricity Order.

9.2 This Part is divided into three sections, commenting on:

(a) first, the statutory grounds of appeal that apply under the statutory framework (**Section 9**);

(b) second, the standard of review to be applied in determining whether to allow this appeal (**Section 10**); and

(c) third, the materiality threshold that applies and why it is met for this appeal (**Section 11**).

9.3 This is the first appeal under Article 14B of the Electricity Order since the amendments introduced by the Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015. However, in 2015 the CMA determined two separate appeals, brought by *Northern Powergrid*[62] and *British Gas Trading*[63] against the Ofgem RIIO-ED1 price control in Great Britain, which were based on an almost identical GB statutory framework as set out under the Electricity Act 1989.[64] Accordingly, the CMA's determinations in those matters will be relevant in terms of the legal framework, in particular as to the appropriate standard of review.

9.4 The Appellant is also aware that the CMA is currently considering a price control appeal by Firmus Energy (Distribution) Limited under the Gas (Northern Ireland) Order 1996 against a decision by Utility Regulator to modify its gas distribution licence to give effect to the GD17 price control determination.

10 Statutory Framework

10.1 An appeal against an electricity licence modification decision by the Utility Regulator is made by way of an application to the CMA under Article 14B of the Electricity Order.

10.2 Article 14D(4) of the Electricity Order provides that the CMA may allow the appeal if it is satisfied that the decision appealed against was wrong on one or more of the statutory grounds in sub-paragraphs (a) to (e). Those grounds are as follows:

(a) the Utility Regulator failed properly to have regard to any matter mentioned in Article 14D(2);

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62 NPG Determination.

63 BGT Determination.

64 Section 11C Electricity Act 1989 c.29.

(b) the Utility Regulator failed to give the appropriate weight to any matter mentioned in Article 14D(2);

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

(d) the modifications fail to achieve, in whole or in part, the effect stated by the Utility Regulator by virtue of Article 14(8)(b) of the Electricity Order; and

(e) the decision was wrong in law.

10.3 The matters listed in Article 14D(2) are the matters to which the Utility Regulator must have regard:

(a) in the carrying out of the Principal Objective under Article 12 of the Energy Order or Article 9 of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 (as the case may be);[65]

(b) in the performance of its duties under either such Article;

(c) in the performance of its duties under Article 6B of the Energy Order.[66]

10.4 Article 14(8)(b) of the Electricity Order requires the Utility Regulator, in relation to the making of licence modifications, to:

(a) publish the decision and the modifications in such manner as it considers appropriate for the purpose of bringing them to the attention of persons likely to be affected by the making of the modifications;

(b) state the effect of the modifications;

(c) state how it has taken account of any representations duly made; and

(d) state the reason for any differences between the modifications and those set out in the notice by virtue of Article 14(2)(b).

10.5 Article 14(2)(b) of the Electricity Order provides that before making any modifications under Article 14, the Utility Regulator must give notice setting out the proposed modifications and their effect.

10.6 In this appeal, the Appellant contends that the Utility Regulator's Decision should be overturned on one or more of the following grounds.

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65 Article 9 of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 SI 2007/913 deals with, *inter alia*, the principal objective of the Utility Regulator in giving effect to any decision of the SEM Committee, which is to protect the interests of consumers of electricity in Northern Ireland and the Republic of Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the SEM.

66 Article 6B of the Energy Order provides that the Utility Regulator shall carry out its functions in the manner that it considers is best calculated to implement, or to ensure compliance with, any binding decision of the Agency or the European Commission made under the Electricity Directive, the Gas Directive, the Electricity Regulation, the Gas Regulation or the Agency Regulation.

(a) Article 14D(4)(a) – the Utility Regulator failed to have proper regard to any matter mentioned in Article 14D(2)

10.7 The Utility Regulator's relevant obligations under Article 14(D)(2) for the purposes of this appeal are set out below.

(i) The Principal Objective

10.8 Under Article 12 of the Energy Order[67] the Utility Regulator's Principal Objective in carrying out its electricity functions is:

> *…to protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply*.

10.9 Article 12(1A) of the Energy Order expands upon the meaning of "*the interests of consumers*" to include their interests in the fulfilment by the Utility Regulator of the objectives listed in Article 36(a)-(h) of the Electricity Directive, which include: [68]

> *(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;*
>
> *(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.*

10.10 In the NIE Determination, the CC interpreted the duties in Article 36 of the Electricity Directive as being *"part and parcel"* of an overall objective to further the interests of consumers.[69] Considerations of system adequacy and Government policy objectives on energy efficiency are directly relevant to the Utility Regulator's functions in setting a price control for the SONI business under its TSO Licence.

10.11 Article 2 of the Energy Order defines the term "consumers" as including "*both existing consumers and future consumers*". In the absence of further definition, the Appellant submits that "consumer" should also mean an electricity end-user in Northern Ireland, even though such end-users are not direct customers of the Appellant.

10.12 Accordingly, in determining this appeal, the CMA must determine whether, in making the Decision, the Utility Regulator furthered the Principal Objective. Importantly, however, this must

67 The Utility Regulator is subject to a similar duty – also described as the "principal objective" – under Article 9 of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 where it is giving effect to any decision of its SEM Committee.

68 Electricity Directive, Article 36(d) and (f).

69 NIE Determination, paragraph 11.

not be equated with a consumer interest solely in lower prices above all else. The CC confirmed this approach in the NIE Determination:[70]

> *…protecting the interests of consumers may not be a matter of keeping prices for consumers, or individual groups of consumers (some of which may be particularly vulnerable) as low as possible. A licence holder must be able to finance its activities to fulfil its obligations under the Licence, which means that these various objectives and considerations should be seen not just in the short term.*

10.13 The CMA will be familiar with the principle that "*cost minimisation might...not always be efficient, as lowering costs can sometimes lead to foregoing bigger benefits to consumers*".[71] Despite the broad scope of the Utility Regulator's duties and obligations, it appears to have focused its duty to further the wider consumer interest solely on the achievement of cost reductions and omitted consideration of the benefits to the consumer that a properly funded price control would allow the Appellant to deliver as TSO. This is an unduly restrictive interpretation of the Principal Objective to protect the interests of consumers and fails to recognise the application of the Utility Regulator's other statutory duties, in particular the Financeability Duty. The requirement to secure that the Appellant is able to finance its licensed activities is not a subsidiary consideration to protecting the consumer interest.

10.14 Nor should it be interpreted to mean that the interests of current consumers should always be preferred to the interests of future consumers.

10.15 For the reasons explained in this Notice, the Appellant contends that the Utility Regulator has failed to further the Principal Objective in that it has breached its Financeability Duty by failing to ensure in setting the Price Control that the Appellant is financeable, with adverse implications for the Appellant in delivering its services efficiently and in the best interests of customers and consumers.

(ii) <u>The need to secure that all reasonable demands for electricity are met</u>

10.16 Article 12(2) of the Energy Order requires that the Utility Regulator shall carry out its functions in the manner which it considers is best calculated to further the Principal Objective, having regard to:

> *(a) the need to secure that all reasonable demands in Northern Ireland or [the Republic of] Ireland for electricity are met…*

10.17 The Appellant contends that the Utility Regulator has failed to have proper regard to this duty by failing to ensure in setting the Price Control that the Appellant is sufficiently funded, which has the potential to compromise the delivery of the Appellant's Licence obligations.

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70 NIE Determination, paragraph 1.12.

71 Department for Business Innovation and Skills, "*Principles for Economic Regulation*", paragraph 40 (available at https://www.gov.uk/government/publications/principles-for-economic-regulation).

(iii) <u>The need to secure that licence holders are able to finance their regulated activities</u>

10.18 Article 12(2) of the Energy Order also requires that the Utility Regulator shall carry out its functions in the manner which it considers is best calculated to further the Principal Objective, having regard to:

> *(b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order [1992] or this Order…*

10.19 As noted in Part I of the Notice, the Appellant refers to this obligation as the "**Financeability Duty**".

10.20 This obligation refers to the need to "secure" that licence holders are able to finance their regulated activities. This is a strict test and can only be met if the regulator is satisfied that the licence holder can attract sufficient funds efficiently to discharge its obligations under the licence, including carrying out all of the activities which it is required to undertake. This requires an assessment of the revenues required by the licensed undertaking and proof that the undertaking can access such revenues, either from retained earnings or from external sources, typically through equity or debt capital. This assessment must be undertaken and completed in a timely manner to give certainty for the licence holder that funds will be forthcoming and to facilitate efficient business planning.

10.21 There is no legally mandated test as to how this exercise should be conducted. For capital intensive industries the practice has – in general – been to calculate a RAB consisting of the assets required to meet the licence obligations, and to apply a return to this RAB which would be no less than the WACC. For activities where capital is very small relative to turnover, and where opex loom very large, this design is plainly inappropriate. There is little point in applying a WACC to a non-existent or trivial RAB as this would guarantee a result which offered inadequate revenue for the undertaking to operate in accordance with its licence, and for the regulator to discharge its duty to "secure" financeability.

10.22 Therefore, the Utility Regulator must first ensure that it has designed a suitable regulatory framework tailored to the business model under assessment. From here, testing and cross-checking must be sufficiently robust to ensure that the company is financeable under a range of likely scenarios, and not rely on the accuracy of a single set of assumptions. This is particularly important in Northern Ireland at this time owing to the significant changes which are taking place in energy supply there.

10.23 In summary, the Utility Regulator must ensure that SONI must be able to access financial markets to finance its operating and investment activities under a reasonable set of assumptions. The approach must be sustainable and allow the business to able to secure debt facilities at reasonable commercial rates and by being able to provide an adequate rate of return for its shareholders relative to other businesses with equivalent investment risk.

10.24 It is important to note that the requirement to secure that the Appellant is able to finance its licensed activities is not a subsidiary consideration to protecting the consumer interest. There is no trade off: the Utility Regulator must further the consumer interest *and* secure financeability[72].

10.25 For the reasons set out in this Notice, the Appellant contends that Utility Regulator has failed to secure the financeability of the Appellant. As KPMG observes having conducted an assessment as to the Utility Regulator's approach: [73]

> *…the UR does not appear to have undertaken a sufficiently thorough assessment to conclude that the [Final Determination] will allow SONI to finance its activities on a stand-alone basis. Therefore, UR's analysis cannot be considered to be a meaningful test of whether SONI is likely to be able to finance its activities and planned investments over the course of the price control.*

10.26 By adopting a defective regulatory design based on RAB*WACC, which is ill-suited to an undertaking with the Appellant's characteristics, and by either not considering, or not taking sufficient note, of the Appellant's evidence from its financiers – both debt and equity holders - that they would not lend unless revenues were more secure, having regard to the Appellant's activities and the associated risks, the Utility Regulator has gone wrong in discharging its duty.[74]

(iv) Promoting efficiency and economy

10.27 Article 12(5) of the Energy Order provides that, subject to paragraph (2), the Utility Regulator shall carry out its functions in the manner which it considers is best calculated:

> *… to promote the efficient use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity…*
>
> *… to secure a diverse, viable and environmentally sustainable long-term energy supply…*

10.28 The requirement to act in the manner "best calculated", while not as strong as the obligation to "secure", nonetheless imposes a high standard on the Utility Regulator. It must always prefer a superior approach to one that is clearly inferior where it has a margin of discretion.

10.29 The Appellant submits that the Utility Regulator's Decision is wrong in relation to a number of errors set out in this Notice because it failed to have regard to its duty to promote efficiency and economy. However, in all such cases, the Appellant primarily pleads a breach of the Financeability Duty based on the same facts and therefore does not separately re-state those errors in relation to the efficiency and economy duty.

(b) Article 14D(4)(c) – the Utility Regulator's decision was based, wholly or partly, or an error of fact

10.30 Article 14(D)(4)(c) concerns decisions taken by the Utility Regulator which were wrong as a matter of fact, insofar as that error affected its decision.

72 Indeed, securing the Appellant's financeability is in the furtherance of the consumer interest.

73 KPMG1, paragraph 1.25 **[MC1/1/6]**.

74 Further discussion of the Appellant's non financeability under the Decision is provided in AS1 and FS1.

10.31 In the NPG Determination, the CMA described its jurisdiction to make factual judgments as follows:[75]

> *...we have not limited ourselves to errors of law or judicial review grounds, but have duly taken the merits of the case into account when considering whether any of the statutory grounds of appeal is made out.*

10.32 Drawing on this the Appellant submits that the Utility Regulator's Decision is wrong because it is compromised by important errors of fact in a number of important areas – including as detailed in Error 1(b) on the errors in the Utility Regulator's limited assessment, Error 1(c) on the Utility Regulator failure to conduct a complete financeability assessment, Error 9 on the failure to provide adequate payroll allowances for network planning staff (and the assertion that it had included the TUPE costs of opex staff when there is no evidence that it did), Error 10 on the failure to provide adequate pensions allowances, and Error 11 on the failure to provide adequate capital expenditure allowance.

(c) Article 14D(4)(d) – the modifications failed to achieve, in whole or in part, the effect stated by the Utility Regulator by virtue of Article 14(8)(b)

10.33 Article 14(8)(b) of the Electricity Order requires the Utility Regulator to state the effect of the modifications set out in its decision. Where the CMA finds that the modifications do not achieve the stated effect, it must uphold the appeal.

10.34 The Appellant notes that helpful guidance can be drawn from the CMA's determination in the British Gas Trading Appeal, where the CMA took into account the following factors in assessing the effect Ofgem had intended would be achieved by licence modifications setting a particular incentive mechanism – the "IQI":[76]

(a) any policy statements made by Ofgem during the RIIO-ED1 price control process including, in particular, at the Draft and Final Determination stages;

(b) any explanations given by Ofgem in support of such policy statements;

(c) any responses made by Ofgem to comments by consultees in connection with such policy statements; and

(d) evidence given by Ofgem at an oral hearing conducted by the CMA.

10.35 Taken cumulatively, such evidence was deemed sufficient to inform the CMA of Ofgem's <u>policy</u> and therefore what it had <u>intended to achieve</u>. This in turn enabled the CMA to review Ofgem's decision to determine whether – as a matter of fact – the modification did or did not achieve the effect intended. In contrast, no guidance was given by the Utility Regulator in terms of the intended effect of the licence modifications. In addition, as explained below, additional items were introduced that were unrelated to the Final Determination and further items were subsequently introduced without any further consultation.

[75] NPG Determination, paragraph 3.40.

[76] BGT Determination, Section 6 Changes to Information Quality Incentive.

10.36 In this Notice, the Appellant submits that the Utility Regulator's Decision is wrong because of a number of errors of this type – including as detailed in Error 6 on the Utility Regulator's failure to manage uncertainty by creating additional uncertainty through implementing an unworkable two-stage process, Error 7 on the Utility Regulator's unjustified creation of uncertainty through failure to provide guidance on the application of the demonstrably inefficient and wasteful expenditure provision and Error 8 on the Utility Regulator's unjustified creation of uncertainty through the introduction of the Qt adjustment.

(d) Article 14D(4)(e) – the decision is wrong in law

10.37 The Appellant submits that the final ground – error of law – covers a host of potential areas where the Utility Regulator has misdirected itself as to the relevant law or failed to discharge its legal duties. For example, the Utility Regulator's decision might be deemed to be wrong as a matter of law if it has:

(a) misdirected itself as to the obligations to which it is subject in making its decision;

(b) failed to uphold the Appellant's legitimate expectations; or

(c) failed to take proper account of relevant considerations.

10.38 In this Notice, the Appellant submits that the Utility Regulator's Decision is wrong because it is compromised by errors of law as explained in Error 1(b) on the errors in the Utility Regulator's limited assessment, Error 1(c) on the Utility Regulator failure to conduct a complete financeability assessment, Error 9 on the failure to provide adequate payroll allowances for network planning staff, Error 10 on the failure to provide adequate pensions allowances, and Error 11 on the failure to provide adequate capital expenditure allowance.

(i) <u>Failure to uphold the Appellant's legitimate expectations</u>

10.39 A public authority which has, by a promise or practice, conferred on a person a legitimate expectation of a procedural or substantive benefit may not frustrate that expectation if to do so would be so unfair as to amount to an abuse of power. Such assurances need not be express; it may arise from an implicit promise or a regular practice.[77]

10.40 Once a legitimate expectation has been demonstrated, the burden of proving that the frustration of a legitimate expectation was justified lies on the authority: if the authority does not provide evidence to explain why it acted in breach of a legitimate expectation, it is unlikely to be able to persuade the court that there was any overriding public interest sufficient to defeat it.[78] A public authority must still justify decisions that are contrary to legitimate expectations.

(ii) <u>Failure to take proper account of relevant considerations relating to the Price Control</u>

10.41 A failure to take proper account of the appropriate considerations (that is, that relevant considerations have been disregarded or irrelevant considerations taken into account) is an established ground for judicial review.[79] The relevant test is whether "*a consideration has been*

77 *R (Theophilus) v Lewisham London Borough Council* [2002] 3 All ER 851, paragraph 16.

78 *Paponette v Attorney General of Trinidad and Tobago* [2012] 1 AC 1, paragraphs 37-38 and 42.

79 *R (Alconbury Developments Ltd) v Secretary of State for the Environment, Transport and the Regions* [2003] 2 A.C.295.

omitted which, had account been taken of it, might have caused the decision-maker to reach a different conclusion”.[80]

(iii) Procedural unfairness

10.42 In the *Phoenix Gas Determination*, the CC confirmed that in addition to having regard to the duties of the Utility Regulator under the Energy Order, it must also have due regard to principles of regulatory best practice in making its determination:[81]

> *In making our determination, we are required to have regard to the duties of the UR as set out in the Energy Order…[…] In addition to taking into account the statutory duties set out in the Energy Order, we have also had due regard to established general principles of administrative law and principles of regulatory best practice (i.e. that regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed).*

10.43 In addition, the CC has confirmed that the phrase “wrong in law” (which is also used in the Energy Act 2004 and the Electricity Act 1989) includes the public law concept of procedural unfairness / breach of natural justice.[82] This includes the need to consult with an open mind, to allow parties to make representations and to provide clear reasons for its decisions. The Appellant notes that these types of errors are often determined to arise where a regulatory authority has not conducted a process in line with good regulatory practice.

10.44 In this Notice, the Appellant submits that the Utility Regulator’s Decision is wrong because of a number of errors of this type, in particular, as regards legitimate expectation, where This consideration is particularly relevant to the Appellant’s agreement to assume legally inherited costs in relation to the transfer of network planning from NIE in 2014, as detailed at Error 9, the failure to provide adequate payroll allowances for network planning staff and Error 10, the failure to provide adequate pensions allowances. The Appellant so agreed on the express basis that it would be reimbursed for the costs of doing so in relation to TUPE and pensions. In the Appellant’s submission, the Utility Regulator has walked away from this undertaking despite the Appellant’s express reliance upon it.

11 Standard of review

11.1 The Electricity Order is silent as to the standard of review that the CMA must adopt when assessing the specific grounds of appeal listed in Article 14D(4) as stated in the Notice. In practice, the CMA – and its predecessor the CC – has regarded its function as being to determine whether the relevant decision was wrong in respect of the stated grounds of appeal. Accordingly, the standard of review under an Article 14B(1) appeal clearly differs from – and is less restrictive than – the standard which is appropriate for judicial review proceedings and is one which requires an examination of the merits of the decision in question.

80 *R v Parliamentary Commissioner for Administration, ex parte Balchin* [1998] 1 PLR 1, [35]. This is the judicial test to be applied, and the CMA’s review can of course be wider in scope.

81 The *Phoenix Gas Determination,* paragraphs 3.16-3.20.

82 *E.ON v GEMA*, paragraph 5.18.

11.2 For example, in *British Gas Trading*, the CMA confirmed that it had a greater remit to determine an appeal than it would have had if it were confined to judicial review grounds, stating: [83]

> *We agree that we are not limited to reviewing the decision on conventional judicial review grounds and that we are not only able, but required by EA89, to consider the merits of the decision under appeal, albeit by reference to the specific grounds of appeal laid down in the statute.*

11.3 The Appellant acknowledges that this is not to say that the CMA must substitute its decision for that of a regulator merely because it might have reached a different decision in the circumstances. Indeed, the CC in *E.ON v GEMA* has stated that:[84]

> *…it is not our role to substitute our judgment for that of GEMA simply on the basis that we would have taken a different view of the matter were we the energy regulator.*

11.4 The CC continued as follows:[85]

> *…our role is to determine whether GEMA's decision is wrong, because it has failed properly to have regard to, or failed to give the appropriate weight to, the matters to which GEMA must have regard, or because GEMA has erred in law or in fact. In our view, this test clearly admits of circumstances in which we might reach a different view from GEMA but in which it cannot be said that GEMA's decision is wrong on one of the statutory grounds. For example, GEMA may have taken a view as to the weight to be attributed to a factor which differs from the view we take, but which we do not consider inappropriate in the circumstances.*

11.5 There is therefore a distinction to be made between:

(a) grounds in respect of which the Utility Regulator is found by the CMA to have clearly reached a wrong decision on one or more of the statutory grounds – in such cases, the CMA must allow the appeal; and

(b) grounds in respect of which the CMA might itself have reached a decision which differed from that of the Utility Regulator – in such cases, the CMA must consider whether the Utility Regulator's approach in reaching that decision was nevertheless <u>appropriate and reasonable in the circumstances</u>. If the Appellant can demonstrate that the decision was unreasonable and cannot therefore stand, the CMA must allow the appeal.

11.6 The specific errors the Appellant has appealed have caused the Utility Regulator's decision to be wrong. Consequently, for the reasons detailed in, the Appellant submits that the CMA must find and remedy the errors detailed in Part IV of this Notice. The Appellant requests the relief set out in Part V of this Notice.

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83 BGT Determination, para. 3.24.

84 *E.ON v GEMA*, paragraph 5.11.

85 *E.ON v GEMA*, paragraph 5.12.

12 Materiality threshold

12.1 The Appellant is mindful of the CMA's obligation to give effect to the overriding objective of disposing of appeals fairly and efficiently within the relevant time periods prescribed by legislation.[86] In support of this objective, the Appellant has limited its grounds of appeal to those errors which have a material effect on the price control. The Appellant notes however that there are a number of further areas in which the Utility Regulator has erred in its findings which are not addressed in detail in this Notice as explained in BT1.

12.2 The CMA in the BGT Determination confirmed its approach to materiality as follows:

> *Whether an error is material must be decided on a case-by-case basis taking into account the particular circumstances of each case. Relevant factors would include the impact of the error on the overall price control, whether the cost of addressing the error would be disproportionate to the value of the error, whether the error is likely to have an effect on future price controls, and whether the error relates to a matter of economic or regulatory principle. This list is not intended to be exhaustive.*

12.3 The Appellant submits that each of the errors subject to this appeal is of such significance and is therefore material. In terms of financial impact alone, the Appellant estimates that the errors in the Final Determination, as set out in this Notice, amount to an under-recovery of £14.7 million. This is a significant sum given that the Appellant has been funded for less than £69 million for the Price Control Period,[87] and in light of the limited headroom available to the Appellant within the proposed Price Control.

12.4 However, the key issues arising from this Price Control determination are not confined to the under-recovery of costs. Of fundamental importance to this Appeal are:

(a) the unsuitability of the WACC*RAB regulatory framework as a method of regulating the Appellant's business; and

(b) the unprecedented level of uncertainty arising from the Utility Regulator's determination.

12.5 The combination of these factors creates an unsustainable funding situation which, if left unresolved, would have important ramifications for future price controls and for Northern Ireland consumers.

[86] The Competition Commission's Energy Licence Modification Appeals Rules, paragraph 4.1, as extended to Northern Ireland appeals pursuant to the CMA's consultation on energy licence modification appeals rules for Northern Ireland (https://www.gov.uk/government/consultations/energy-licence-modification-appeals-rules-for-northern-ireland).

[87] This figure is calculated on the basis that although the Utility Regulator has set the allowance at £97 million, as per page 4 of the Final Determination, £28 million of this allowance has been provisionally estimated to cover the cost of network planning activities. As there is currently no mechanism for recovery of these costs under the Licence Modifications (other than in respect of projects which do not proceed to construction), the total allowances awarded to the Appellant actually amount to £69 million.

PART IV

GROUNDS OF APPEAL

13 Overview

13.1 This part of the Notice details the three Grounds, and specific errors, on which the Appellant brings this appeal and seeks the relief set out in Part IV.

13.2 The Appellant requests that the CMA read AS1 by way of background, which explains both why the Decision does not secure the Appellant's financeability and the implications that arise for the Price Control Period.

13.3 The core of the Appellant’s appeal is that the Decision is rendered defective by a number of serious errors which have the effect of rendering the Appellant unfinanceable. This includes errors of assessment, the omission of allowances for the costs that must be expended or remuneration for the capital which must be in place to finance its activities as TSO, and the provision of inappropriate and adequate mechanisms for dealing with risk and uncertainty which apply to more than 35 per cent of revenues. These errors constitute a breach of the Financeability Duty, namely Utility Regulator’s duty to secure that the Appellant is able to finance its regulatory obligations over the Price Control Period. The provision of an unfinanceable Price Control inevitably means that the Decision is also in breach of the Principal Objective, namely the Utility Regulator’s duty to protect the interests of consumers of electricity in Northern Ireland.

13.4 The Grounds on which the Appellant brings this Appeal encompass the various errors made by the Utility Regulator:

(a) **Ground 1: the Financeability Methodology Ground:** The Utility Regulator failed to conduct a proper assessment of the Appellant’s financeability, including as a result of using a methodology which was unsuited for a business of the Appellant’s type and the risks faced in this Price Control. This inevitably resulted in inadequate revenue being generated for the Appellant.

(b) **Ground 2: the Revenue Uncertainty Ground:** The Utility Regulator failed to resolve certain issues in the Decision and, instead of *ex ante* estimating agreed costs to provide an incentive to superior performance and/or by allowing, where appropriate, for re-openers, it resorted to an open-ended scrutiny, both *ex ante* and *ex post*, of a significant element of the Appellant’s expenditure over the period. The net effect of the Utility Regulator’s approach is that the Appellant cannot plan with the security of knowing what its revenues are going to be and, as important, its bankers and its equity funders can have no confidence of a secure income stream on which to lend.

(c) **Ground 3: the Inadequate Allowances Ground:** The Utility Regulator unjustifiably disallowed or neglected certain specific costs which the Appellant is required to incur to fulfil its functions and Licence obligations.

13.5 The Appellant explains below how the Utility Regulator’s decisions in respect of each of these grounds represent a failure to discharge its Financeability Duty and/or are vitiated by other appealable errors. The remainder of this Section provides context to these errors by:

(a) summarising the Appellant's expectations that the design of the Price Control would be based on and the need to secure financeability, taking into account the particular nature of the TSO business;

(b) explaining the extent of the underfunding provided by the Price Control; and

(c) summarising the implications of underfunding for the Appellant's operations and performance of its licence obligations.

14 The Appellant's expectations

14.1 The Appellant has invested considerable effort in engaging with the Utility Regulator, from the commencement of consultations in December 2013 and throughout the three and half years since. Throughout this time – and in particular at the commencement of this engagement – the Appellant emphasised the importance of putting in place a Price Control that would achieve fair remuneration for the efficient delivery of licensed activities, obligations and associated risks.[88] The Appellant emphasised three principles that it believed should underpin the design of the Price Control:[89]

(a) Reflecting Government policy – The Price Control should recognise that the period to 2020 presents unusually challenging problems and greater risks. These arise from the Appellant's role in progressing and implementing services to achieve the wider energy policies of the Department and the Utility Regulator, including enhanced service levels. This fact alone justifies a departure from past regulatory methodologies.

(b) Regulatory uncertainty – In progressing to a new review period and in the context of a changing and challenging environment, the price control design should recognise the uncertainties involved, address the enhanced risk, and incentivise innovation and high performance in managing transmission system operations.

(c) Financeability – It is fundamental that the Appellant is properly resourced in order to carry out its licensed activities and obligations through the application of an appropriate price control framework. By contrast, the conventional application of a regulated return on the RAB approach is not fit for purpose. This is because, owing to the asset-light nature of the TSO business, this approach yields revenue allowances which are inadequate for the Appellant's needs.

14.2 These principles were reflected in further submissions, supporting experts reports and the Business Plan papers that the Appellant provided the Utility Regulator to aid the design of the framework and the setting of the Price Control. This included the submission of a detailed paper outlining a financeability framework that would take appropriate account of the Appellant's particular characteristics as an asset-light business, and the unprecedented risk and uncertainty faced in the next Price Control Period.[90] The paper was supported by expert evidence from KPMG which explained why a traditional financeability assessment focusing on testing financial

88 See, for example, the "Objectives" listed by the Appellant in the Principles & Key Issues Paper, page 7 **[NOA1/8]**.

89 Principles & Key Issues Paper, page 7 **[NOA1/8]**.

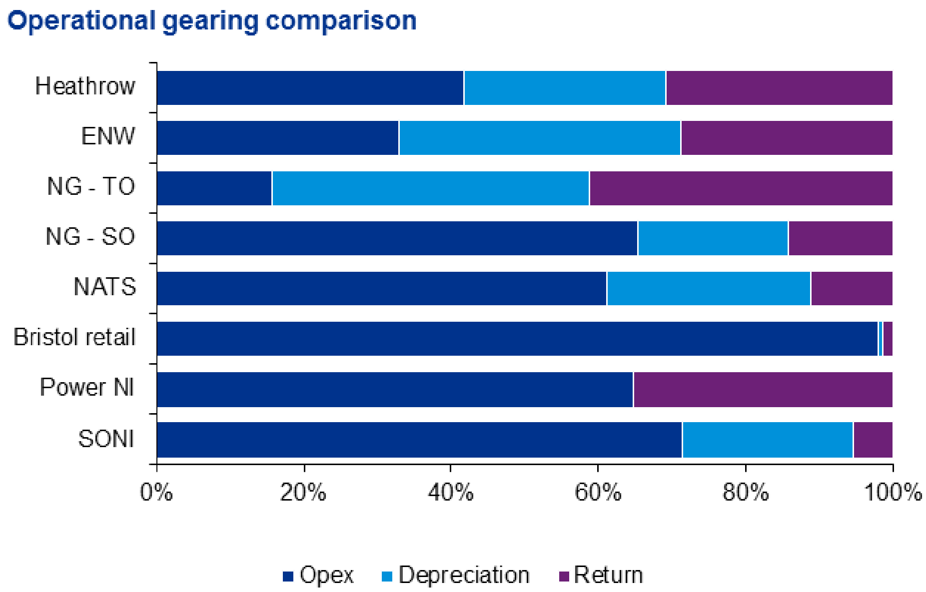
90 Business Plan Submission, "Paper 6 – Risk and Uncertainty: The Financeability Framework", **tab 6 of [BT1/31]**.

ratios was insufficient evidence for an asset-light business, as it failed to take into account the business's more limited ability to withstand shocks.[91]

14.3 The Appellant emphasised the following attributes as a TSO and an asset-light business, as factors that would need to be taken into account in designing the Price Control:[92]

(a) Physically asset-light – the Appellant is asset light with significant operational activities that are not related to any major assets (it is not a TAO). It has no significant RAB, equity return or balance sheet upon which to fund investments as demonstrated in Figure 2 below.

Figure 2: Operational gearing comparison



Investment in assets is typically more risky and its limited asset base is comprised of assets with short lives. Working and contingent capital is as important as equity capital, including to protect against the significant income recovery risk that arises from factors outside its control as TSO, in particular in relation to its DBCs and System Services payments.

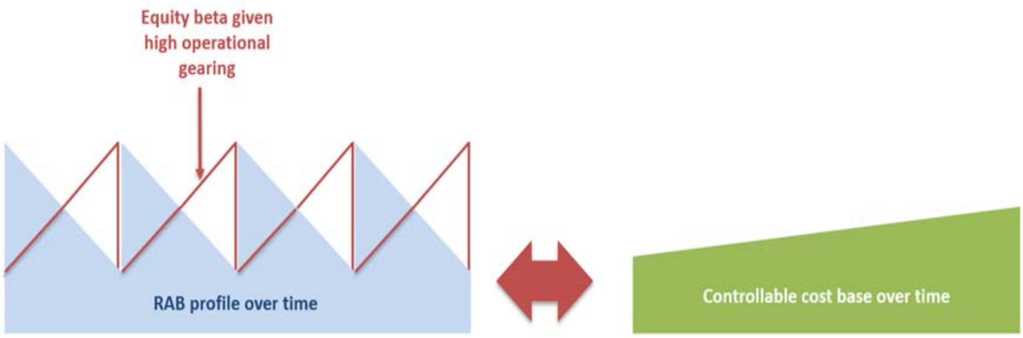
(b) Significant funding responsibilities – the Appellant must undertake significant investments in response to Government or regulatory policy decisions, which it has little control over in terms of scale or timing and or when it has to approach investors to secure funding. The costs of network planning projects increase the need for funding. These investments gives rise to significant movements in its small RAB over short periods of time, which results in unstable financial ratios. Unstable ratios present significant problems in securing debt financing. The rapidly-depreciating nature of the bulk of SONI's assets means that SONI's RAB, and therefore the return thereon, exhibits a saw-tooth pattern, with periods of steady decline over the seven-year period, followed by bursts of

91 Business Plan, Paper 7: KPMG "SONI's revenue model 2015 – 2019" dated 10 October 2014", exhibited at **tab 7 of [BT1/31]**.

92 Business Plan, "Paper 6 – Risk and Uncertainty: The Financeability Framework", pages 5-7, **tab 6 of [BT1/31]**.

investment. Similarly, SONI's investment behaviour exhibits a saw-tooth pattern which is the mirror image of the RAB, as show in Figure 3 below. The last substantial investment which SONI made, prior to investment in relation to the I-SEM, was in 2007, in connection with the construction of the SEM.

Figure 3: Illustration of saw-tooth investment pattern of RAB profile compared to controllable cost base



(c) High operational gearing – the value of the business's assets is low relative to turnover and operating costs (in 2015/16 SONI's average RAB was £7.4 million compared to total revenues of £109 million), a significant proportion of which are fixed or externally controlled. This creates high operational gearing, meaning the Appellant has higher exposure than asset-heavy utilities to external market factors and volatility in cash flows. Its asset-light nature means it has less of a financial buffer to cope with the fluctuations. This increases its risk profile.

(d) Value add – as TSO, the Appellant plays a critical role standing at the centre of the electricity value chain, keeping the lights on in Northern Ireland and acting as trustee for payments concerning DBC, TUoS and Systems Services payments despite its own costs representing less than 2 per cent of costs for consumers.

(e) Specialised and skilled labour force – the operation of the transmission network requires a highly specialised and skilled labour force, which is critical to the safe and secure operation of system and the management of high systemic and catastrophic risks of operational failure.

(f) High intangible assets – the Appellant has significant intangible assets in knowledge, and expertise, including human capital, required to undertake the sophisticated TSO function. The Appellant believes insufficient consideration was given as to what this might mean in terms of securing the Appellant's financeability, but this issue is not the subject of this appeal.

14.4 In particular, the Appellant emphasised[93] the need for the Utility Regulator to focus on addressing two significant new issues: first, the need to ensure a suitable mechanism for costs recovery for network projects, and, second, the need to address the Appellant's increasing

93 Business Plan, "Paper 2 – Overview Paper: Context for the 2015-20 Control, 15 October 2014", at tab 2 of **[BT1/31]**.

contingent capital requirements. As Bill Thompson explains in BT1, neither of these issues has been resolved under the Decision.

14.5 Overall, the Appellant expected that the Utility Regulator would approach the price control in a manner that would take into account the scale of activities, risks and investments the Appellant is required to undertake and manage during the 2015 to 2020 period. The Appellant sought to assist by obtaining input from independent experts to assess financeability, how it can be measured, and what is required in order to satisfy it. In doing so, the Appellant argued that a traditional revenue regulation framework and financial metrics tests are not appropriate for the TSO business because, for example, it overlooked the relatively small proportion of total capital employed that is reflected in the RAB and the high operational gearing exhibited. Not surprisingly, the reliance on the RAB*WACC approach leads to underfunding notwithstanding the modest uplift in the WACC made by the Utility Regulator after the Draft Determination because of the low RAB. No information was provided as to what work the Utility Regulator had undertaken when calculating the WACC uplift, although the Utility Regulator stated that it had engaged further with consultants.[94]

14.6 The Appellant's Business Plan set out a framework which sought to reflect the businesses characteristics. It proposed a remuneration framework based on a margin of 11 per cent on costs consistent with the benchmark of 10-12 per cent on controllable costs, assuming an "A" credit rating. WACC*RAB on tangible capital was integrated within this overall margin derived benchmark framework. In addition the Business Plan sought a provision to remunerate the £22 million of contingent capital (£12 million debt and £10 million equity) held by the Appellant based on the approach employed by the Utility Regulator to remunerate contingent capital for Power NI[95], risk adjusted for the lower risk in the Appellant's TSO business. The £22 million represents a very significant proportion of the Appellant's capital base.

14.7 The approach proposed in the Business Plan would have allowed the Appellant to meet appropriate credit metrics (i.e. consistent with an A rating based on EBIT margin metrics) and it would have remunerated streams of contingent and working capital. It would have secured the Appellant's financeability in a manner that was robust to further changes and the increased risks in the business going forward.

14.8 The Utility Regulator rejected these submissions in setting the Price Control and choosing instead to roll-over the WACC*RAB framework, and not allowing allowances for contingent capital or a margin. This ultimately resulted in the Utility Regulator proposing a non-financeable regulatory framework, which was exacerbated by the additional error set out in this Notice.

15 The funding gap in the Price Control

15.1 The Final Determination states that "*the Utility Regulator has determined that its approach will allow the Appellant to finance its licence activities and services to protect the interests of consumers*".[96] It does not do either. The Appellant is not financeable under the Decision, for the

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94 See paragraph 268 of the Final Determination **[NOA1/12]**.

95 Utility Regulator, "Approach to the 2014 Power NI Supply Price Control: Consultation Paper", 8 February 2013 (https://www.uregni.gov.uk/sites/uregni/files/consultations/Consultation%20on%20approach%20to%20the%202014%20Power%20NI%20supply%20price%20control_0.pdf)

96 Paragraph 323 of the Final Determination **[NOA1/12]**.

reasons explained below; nor are the best interests of consumers being served. The Utility Regulator estimates that consumers will save 70p per annum. In the context of average consumer bills in Northern Ireland this is a trivial sum against the significant risks from underfunding and ongoing uncertainty.

15.2 In AS1, Aidan Skelly explains why the Decision does not secure the Appellant's financeability. First, he considers the expected returns that may be available to the Appellant in light of the Utility Regulator's Decision on submitted costs, combined with a risk based assessment of other non-recoverable costs that may arise.[97]

15.3 The various shortfalls in expected returns are set out in Figure 4 below. The shortfall to SONI from the clearly identified binary errors made by the Utility Regulator in respect of allowances amounts to £7.840 million (as set out in the first four rows of columns A and C). In addition to the shortfall from binary cost disallowances when the WACC RAB framework is compared to a benchmarked EBIT margin of 11% of controllable costs, consistent with that recommended by KPMG and applied in a manner consistent with that set out in KPMG's report,[98] the Appellant's investors are subject to a further shortfall of £5.3 million[99] under the Decision.[100] Finally, as a result of the asymmetric risk profile which means that at best the Appellant can simply receive return of its investment but in reality will sometimes "lose", the Appellant has assessed the likelihood of non-recovery of some proportion of the revenues at risk. As explained in AS1, overall the Appellant believes that non-recovery of 4% is likely, giving rise to a shortfall of £1,529 million (as applied in column B to Dt costs and Network project costs below).

Figure 4: Shortfall in expected returns

Shortfall in investor returns (FD case)			
Category	Total spend	Risk factor	Shortfall in investor returns (2015-2020)
	£'000	%	£'000
	A	B	C=A*B
Pensions (ongoing contributions)	1,489	100%	1,489
Network planning staff (opex and capex)	3,177	100%	3,177
Failure to provide allowance for DS3/Smart Grids and pricing error	1,624	100%	1,624
PCG Remuneration	1,550	100%	1,550
Dt costs (excluding network projects) - expected loss	20,814	4%	833
Network project costs - expected loss	17,400	4%	696
Margin shortfall	5,302	100%	5,302
TOTAL FUNDING GAP			**14,670**

97 Further details as to the assumptions applied are provided in paragraphs 121-124 of AS1 **[AS1/1]**
98 KPMG1, section 9 **[MC1/1/103-126]** and KPMG2 **[MC1/2]**
99 This is after adjusting for the binary error through the Utility Regulator's exclusion of provision of remuneration for the PCG.
100 In AS1, Aidan Skelly discusses the differences between the Final Determination and the Business Plan.

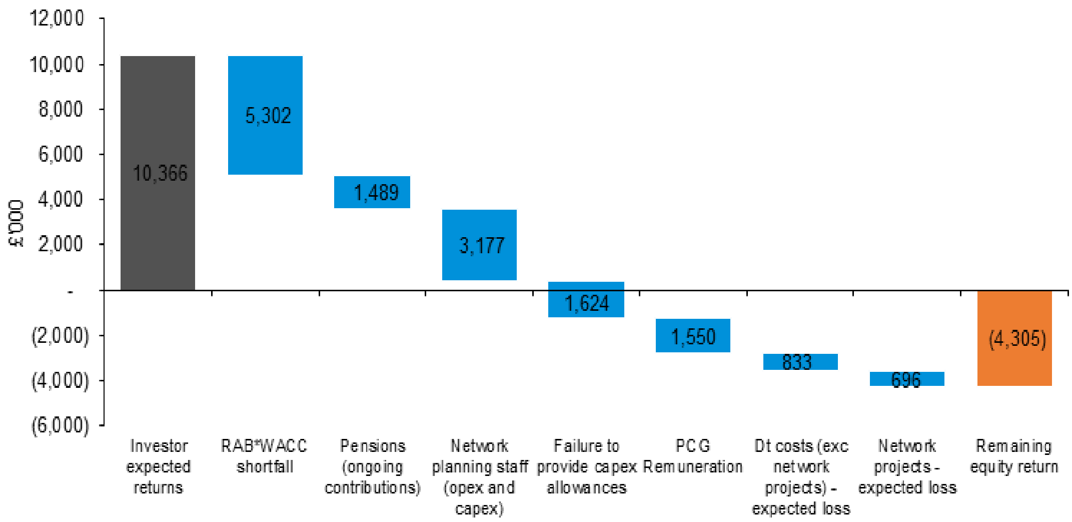
15.4 Overall, investors expect to receive £14.7 million less under the Decision[101] than they might reasonably expect by reference to benchmarked market returns of an EBIT of 11 per cent of controllable costs.

15.5 In fact, as explained by Aidan Skelly, so significant is the risk profile and the disallowances that returns are expected (on average) to be negative for the forthcoming period. Even if it was assumed that the Utility Regulator's own return under the WACC RAB model was sufficient to compensate investors (which the Appellant disputes), the Appellant would still see a shortfall of £9.4 million[102] given the specific disallowances and asymmetric risk. In AS1, Aidan Skelly refers to KPMG3 in which KPMG notes: [103]

> *A key driver of equity financeability is also that investors can expect, on average, to earn the equity return allowed by the regulator. Where a price control is set such that mean expected returns are significantly below this allowed return, the business will not be able to attract capital and hence will not be financeable.*

15.6 The Appellant outlines the various disallowances and their impact on equity returns in Figure 5 below:

Figure 5: Shortfall in investor returns under the Final Determination



15.7 In AS1, Aidan Skelly emphasises the scale of the shortfall in investor returns noting:[104]

> *… the returns available to the equity investor are wholly unacceptable on the basis of the funding gap that results from the analysis of expected returns. This is not some sort of "marginal" result.*

15.8 In addition, he explains that the Appellant has not been able to secure financing from debt or equity providers based on the Utility Regulator's Decision. He confirms:[105]

101 As explained in AS1, the shortfall on expected returns is calculated to be £14 million under the Business Plan case.
102 This figure is calculated by deleting the provision of £5.3 million, which represents the difference between a margin and RAB* WACC (excluding the PCG) from the funding shortfall of £14.7 million.
103 KPMG3, paragraph 1.39 **[MC2/1/6]**
104 Paragraph 132, AS1 **[AS1/1]**
105 Paragraph 39, AS1 **[AS1/1]**

> *The principal reason for lack of access to the required capital is that the levels of remuneration contained in the Final Determination do not provide enough of a buffer either for lenders to be confident that SONI will be able to service its debt liabilities; or for its equity holders to be confident that they will be able to achieve returns commensurate with the risks that SONI faces.*

15.9 As described in AS1, the Appellant has recently sought to put in place facilities for investments in I-SEM, DS3 and network projects and to renew a facility for excess DBCs. Having had sight of the Final Determination, the banks have firmly decided that they do not regard this regulatory position as one they are prepared to fund at least without a guarantee from EirGrid or Letters of Comfort from the Utility Regulator.

15.10 The invitation to submit Dt claims for assessment as and when funds are needed – as expressed by the Utility Regulator in its letter of 31 March 2017 – does not go any way towards providing either the banks or the Appellant with sufficient certainty. Aidan Skelly confirms:[106]

> *…the banks identified concerns about the extensive reliance on the Dt mechanism to deal with uncertain costs.*

15.11 In addition, as explained in paragraph 324 of BT1, recovering costs under the Dt mechanism is not easy – even under the current process, it can take at least a year for what would appear to be straightforward costs to be approved.

15.12 Evidence of the responses received from three international banks, two of whom have long-standing relationships with the EirGrid Group, is provided in a confidential paper from the Appellant's financial advisers, Goodbody Corporate Finance, exhibited to AS1.[107] As Aidan Skelly explains, the banks' reservations stem from the risks and uncertainties that the Appellant faces on the returns on Significant Projects, including PCNPs. Moreover, the Utility Regulator's refusal to decide outstanding matters such as pensions or contingent capital adds to the risks and uncertainties. This Decision has been issued eighteen months after it was scheduled to be adopted and it is evident that the banks share the Appellant's lack of confidence in the Utility Regulator's ability to produce bankable solutions. It is mark of regulatory failure that the lenders require more than a clear Final Determination to assess security and require something further.

16 Faced with no funding, what are the implications of an unfinanceable business

16.1 In AS1, Aidan Skelly comments on the implications of the business being unfinanceable explaining:[108]

> *The implications for SONI of the Utility Regulator's failure to secure its financeability are significant. The consequence for SONI of being unable to secure adequate financing, either from debt providers or from its equity investor, is that it will be unable to deliver the Significant Projects that are of benefit to electricity consumers and ultimately to the economic development of Northern Ireland.*

106 Paragraph 114 of AS1 **[AS1/1]**
107 **[AS1/6].**
108 Paragraph 138 of AS1 **[AS1/1]**

16.2 The shortfalls and revenues at risk mean that the business is unable to plan properly and efficiently to deliver on its obligations and secure funding to deliver key outputs. In essence, the Utility Regulator is asking the Appellant to operate on a '*trust me*' basis – as if to say '*we will use our expertise to evaluate your decision-making and assess what your needs are, and after your work is complete, we will examine whether the work has been executed properly and does not fall foul of our DIWE principle, and only then will we decide if you can recover all or some of your costs'.* The Appellant also requires funding for its day to day operations especially in discharging its "custodial" role, in collecting and paying out sums, however, under the Decision insufficient funds are available.

16.3 In AS1, Aidan Skelly outlines the options which the SONI Board has discussed in order to realise the necessary capital so as to be able to fund the necessary investments required during the Price Control Period. These include realising capital through asset disposal. The only realisable asset is Castlereagh House in Belfast – i.e. the Appellant's control centre, which is a critical piece of infrastructure in Northern Ireland. Alternatively, the Appellant could seek to issue new capital, which would ultimately dilute EirGrid's shareholding. This of course would give rise to significant transaction costs if an investor could be found (which may be unlikely given it is not an attractive investment proposition).

16.4 No firm decisions have been made by the SONI board pending the outcome of the appeal. It is likely, however, that as a minimum the business would need to be significantly restructured. In the longer term, this would be likely to cause costs to rise for the Appellant because it would be more dependent on external service providers.

16.5 The Appellant sets out below a summary of the wider impacts of this failure to ensure the Appellant's financeability on the achievement of desirable outputs in a timely manner, on the stability of the Northern Ireland electricity market and on consumers more generally. These impacts described are those that arise if the CMA does not correct the errors identified in Part IV in this appeal although some of these impacts have already crystallised or become more certain in the 18 months that has already passed since the intended 1 October 2015 start of the Price Control Period, as indicated in FS1 and explained in further detail in AS1.

(a) Impact on outputs

16.6 In the absence of sufficient available funding to secure Financeability, the Appellant fears there is likely to be a negative impact on its ability to deliver on key development and operational outputs, which are intended to deliver significant benefits to Northern Ireland customers.

(i) Risk of delay

16.7 The inadequate provision of funding leads to a greater risk of delay in the delivery of key outputs. These key outputs – which include Significant Projects - are described in RJM1. The specific risks of delay include:

(a) an inability to commence full delivery of DS3;

(b) the risk of non-delivery of I-SEM in accordance with planned timescales;

(c) the risk of non-delivering of NPV positive network projects;.

(d) the risk of not being able to meet payments to industry players, thereby increasing their cost of capital; and

(e) the risk of the overall scale of potential benefits to be delivered by Significant Projects being outweighed by the scale of the potential cost because of unwarranted delay.

(ii) Threat to quality of service

16.8 The Price Control has also resulted in a real threat to the quality of service that the Appellant can provide in delivering its normal system operator duties. This includes the Appellant's statutory obligations to ensure the development and maintenance of an efficient, co-ordinated and economical system of electricity transmission which has the long-term ability to meet reasonable demands for the transmission of electricity and contribute to security of supply through adequate transmission capacity and system reliability.

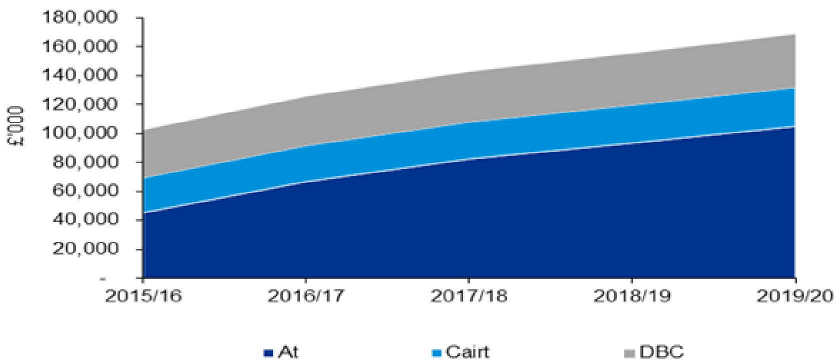
16.9 Given that the Appellant is likely to encounter financing problems in the delivery of key outputs (as outlined above), it will need to prioritise some activities over others. This threatens an overall diminution of the quality of service provided to consumers as discussed in FS1.

16.10 There is also a risk of the Price Control arrangements creating significant difficulties in improving system operation and development tools and thus in ensuring that the maximum quality of service is provided to consumers. For example, the Appellant will be constrained in its ability to explore innovative solutions to improve system operation as there is no *ex ante* provision within the Final Determination to invest in such innovation. With no guarantee of recoverability under the Price Control arrangements, both debt and equity investors will be reluctant to invest funds to explore such works. Such initiatives could have much bigger value for consumers later in the energy life cycle where a small investment at the beginning of the process could yield big rewards for consumers.

(b) Impact on stability of the electricity market

16.11 As explained in AS1, the Appellant is or will be trustee of significant industry revenues (including Dispatch Balancing Costs, System Services Payments, Generator Capacity payments, security of supply contractual payments and underlying tariff recovery) – payments which it collects on behalf of others industry participants and through which it is exposed to significant cash flow or liquidity risks. These revenues form a significant proportion of the Appellant's overall revenue and it is expected they will rise significantly over the Price Control Period. This is demonstrated in Figure 6 which illustrates the expected increase in revenues during the Price Control Period.

Figure 6: Industry revenues



16.12 These revenues are often referred to as “uncontrollable costs” as the Appellant can exercise only very limited influence over them. There is a high risk of these costs deviating from initial allowances and, while the Appellant will receive any difference in future years through the K-factor mechanism, there can be a significant time lag – over two years - for the full recovery of such costs. Therefore, access to a stable debt facility to manage this cash-flow risk is important.

16.13 To date the Appellant has sought to manage this risk by putting in place appropriate revolving credit facilities. In seeking new facilities for such funding, the Appellant’s banking providers now require the provision of a letter of comfort from either the Utility Regulator and/or a guarantee from EirGrid securing the repayment of any shortfall, demonstrating their reluctance to place reliance on the Final Determination. As a result, the Appellant has not been in a position to renew the debt funding previously in place. This is further discussed in AS1.

16.14 The Appellant receives an allowance in respect of the interest payable on debt facilities drawn on year end positions through k factor to manage this cash flow risk[109] but the Price Control does not provide an allowance for managing the payments or any remuneration on equity provided, including that supporting the debt arrangements. As explained in Error 1(b), no remuneration is provided in respect of the PCG currently in place to support the Appellant’s debt facilities. As a result, there is a risk that further support from the Appellant’s shareholders will not be forthcoming. In the event that the Appellant has insufficient recourse to credit, this could give rise to delays in payment to key industry participants. This could have knock on implications in terms of the protection of consumers as cost of capital may rise for these participants and there may be a negative impact on security of supply.

(c) Wider impact on consumers

16.15 The Appellant faces significant challenges over the course of the Price Control Period arising from its pivotal role in rolling out and managing operations associated with policy initiatives and managing external environment challenges. These challenges include the design and implementation of I-SEM, network codes, achieving renewable generation targets and system management issues associated with unprecedented levels of intermittent renewable generation (i.e. through the DS3 Programme).

16.16 These various regulatory policies are aimed at improving services and outputs for consumers. In addition to the adverse effects for consumers from risk of delay and threat to outputs outlined above, any negative impact on the Appellant’s ability to manage or achieve these wide scale changes will result in the consumer not receiving the maximum intended benefits of these policies.

16.17 Where the Appellant does not have sufficient resources to carry out its role because it is unfinanceable, it is ultimately constrained in its ability to maximise the benefit of the work it is able to carry out for the consumer interest. As outlined in AS1, the Appellant has limited discretion when compared to a normal investor in terms of either the scale or timing of investment decisions.

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109 This contrary to the purpose of the k factor which was designed to address minor variances in revenues.

PART IV – GROUND 1

The Financeability Methodology Ground

17 Overview

17.1 Ground 1 concerns the Utility Regulator's failure to conduct an adequate assessment of the Appellant's financeability, in breach of the Financeability Duty (the Financeability Methodology Ground, as defined in paragraph 4.3(a) above).

17.2 The Appellant requests that the CMA read by way of introduction to this topic:

(a) FS1, which describes the Appellant's business characteristics and the risks it faces during the Price Control Period;

(b) BT1, which describes the Utility Regulator's failure to engage with the Appellant as regards the need to adopt an appropriate approach to assessing the Appellant's financeability;

(c) AS1, which explains why the Decision does not secure the Appellant's financeability;

(d) "Financeability of SONI under the 2015 – 2020 price control", a report by KPMG (**KPMG1**) which provides an expert opinion that the Decision does not secure the Appellant's financeability;

(e) "A margin based approach", a report by KPMG (**KPMG2**) which provides an expert opinion on why a margin-based approach is suitable for the Appellant;

(f) "Assessing the risk-return balance for SONI Ltd", a report by KPMG (**KPMG3**), which provides an expert opinion on the Appellant's potential equity returns in different risk scenarios and the implications for the financeability of equity; and

(g) Expert Witness Statement of Andrew Lilico of Europe Economics (**AL1**) which provides an expert opinion on the incentive properties of margin based regulation, including the impact on consumers, as compared to the traditional WACC*RAB model.

17.3 The Utility Regulator failed to conduct an adequate assessment of the Appellant's financeability because of the following errors:

(a) it failed to adopt a price control framework that could secure the Appellant's financeability (**Error 1(a)**);

(b) there were material errors in the limited – and inadequate – financeability assessment it undertook (**Error 1(b)**); and

(c) it failed to undertake a complete assessment, which – had it done so – would have demonstrated that the Appellant is not financeable (**Error 1(c)**).

17.4 Accordingly, the Utility Regulator's Decision was wrong by reference to the statutory grounds detailed in Part III of this Notice, as summarised below:

(a) the Utility Regulator failed under Article 14D(4)(a) of the Electricity Order to discharge its duties under Article 12(2)(b) of the Energy Order, i.e. to have regard to the need to secure that licence holders are able to finance their regulated activities, by conducting an inadequate assessment;

(b) the Utility Regulator erred as a matter of fact by making a series of errors in conduct its assessment as to the Appellant's financeability (Article 14D(4)(c));

(c) the Utility Regulator erred in law by conducting an inadequate assessment of the Appellant's financeability contrary to best regulatory practice (Article 14D(4)(e)); and

(d) the Utility Regulator erred in law by failing to provide sufficient evidence to substantiate its conclusions, contrary to its duty to properly consult (Article 14D(4)(e)).

17.5 The impact of the Utility Regulator's failure to discharge its Financeability Duty through conducting an inadequate financial assessment is set out below, and is further summarised in Sections 15 and 16 of Part IV of the Notice and discussed in AS1, FS1 and BT1.

17.6 The Appellant requests the relief summarised below and set out in Part V of the Notice.

18 Error 1(a): the Utility Regulator failed to adopt a price control framework that could secure the Appellant's financeability

18.1 The Utility Regulator failed to take into account the specific characteristics of and risks faced by the Appellant's business and so failed to secure SONI's financeability.

18.2 The first step in setting a price control is to set out a clear framework for assessing the revenues required by the licensed business to finance its regulated activities and for ensuring sufficient revenues in the price control period. This must be tailored to the specific business under assessment, its risk environment and the role the business plays within the wider regulatory context. The framework must also ensure that any revenues, profits and cash flows available to the regulated company are such that it can secure financing on reasonable terms and in a timely way to meet the efficient costs of delivering on its regulatory obligations.

18.3 As an asset-light business, the Appellant's RAB is small relative to its allowed revenues and represents a relatively limited proportion of its total capital employed, as explained in its Business Plan:[110]

> *SONI is asset light with significant operational activities that are not related to any major tangible investments. It has no significant RAB, equity return, or balance sheet upon which to lever investment. Investment in assets is therefore inherently more risky as there is less of a portfolio effect in their delivery – small numbers of uneven assets with short asset lives comprise a significant portion of the overall low financial value physical assets on the balance sheet. Working and contingent capital is as important as investment capital to an asset light business such as SONI, indeed it is currently of the order of 2.5 times the size of the physical RAB.*

[110] Business Plan, "SONI Revenue Review 2015-2020 Paper 6 – Risk and Uncertainty: The Financeability Framework", paragraph 2.1(a), **tab 6 of [BT1/31]**.

18.4 As a consequence, the Appellant identified concerns that simply applying a WACC*RAB approach would not secure its financeability (given this would only remunerate the risks of activities associated with tangible assets). The Appellant supported its view by annexing evidence from economic experts, as explained in BT1.

18.5 In particular, the Appellant engaged KPMG to assess the current regulatory revenue framework and provide an expert view as to its appropriateness in particular with regard to the expected costs and risks it would face during the Price Control. KPMG duly provided a report which concluded that the regulatory revenue model was not appropriate because: [111]

> *The nature of SONI's business leads to significant cashflow variations relative to the RAB as well as between costs incurred and revenues received. This leads to a significant working capital requirement. The unstable and somewhat unpredictable cashflow profiles combined with a small balance sheet mean that SONI would not be able to access debt capital markets and could not fund new investments at the notional gearing assumed by the regulator – investors would be reluctant to lend to a business of this profile without adequate financial headroom. […] Moreover, the lack of recognition or remuneration of intangible assets, which form the bulk of SONI's business, means that the business under-recovers as it does not receive sufficient returns to cover the costs of financing and remunerate investors for the risks it faces.*

18.6 KPMG concluded that, "*SONI is unlikely to meet the test of being a financeable business under appropriate profitability and financeability metrics"*. KPMG also stated that, "*given the required level of profitability and to ensure actual financeability, several revenue building blocks need to be considered*". This included an EBIT margin aligned with consumer benefits:[112]

> *The rationale for the EBIT margin is to ensure the company remains financeable by remunerating the intangible assets in the business and the risks associated with them. SONI's current return can easily be more than offset by even a relatively minor shock in operational costs, external costs or TUOS revenues. As the return on physical assets does not capture either the value of the intangible assets, nor provide a sufficient buffer against the risks associated with business, and in order to maintain a strong and stable investment grade credit rating, SONI should have an additional, margin derived revenue building block. The analysis in this report provides a benchmark for all the relevant components of the return revenue equal to the EBIT margin of c10-12% on SONI's own costs.*

18.7 The Appellant also annexed a paper from Oxera entitled "*Something for nothing? Returns in low-asset industries*" which concluded:[113]

> *Market evidence suggests that, contrary to the apparent implication of the assumptions within the WACC approach to benchmarking required returns, investors in asset-light*

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111 Business Plan, Paper 7 – KPMG: "*SONI's Revenue Model 2015- 2019*", 10 October 2014, Section 3.12, page 12, **tab 7 of [BT1/31]**.

112 Business Plan, Paper 7 – KPMG: "*SONI's Revenue Model 2015-2019*", 10 October 2014, Section 7, page 32, **tab 7 of [BT1/31]**.

113 Oxera Agenda: Advancing economics in business "Something for nothing? Returns in low-asset industries" annexed to SONI Business Plan, Paper 6 – Risk and Uncertainty: The Financeability Framework, **tab 6 of [BT1/31]**.

businesses still require a profit, reflecting the return on the risks they take from running the business and/or the intangible assets they create as a result of operating the business over time.

Measuring an appropriate level of profit margins is a difficult process – but where a regulator or competition authority is reviewing an asset-light industry, the alternative route of applying the WACC to the tangible asset base appears likely to underestimate the return required by investors.

18.8 Despite the Appellant's detailed submissions and the evidence that a WACC*RAB approach is unlikely to secure Appellant's financeability, in its Draft Determination the Utility Regulator proposed that the framework should remain unchanged, stating:[114]

> *Following a consideration of SONI's submission and other relevant factors, the Utility Regulator proposes to continue to apply the regulatory mechanism of WACC*RAB to remunerate the business for cost of capital employed.*

18.9 In addition, the Utility Regulator repeatedly emphasised the need to prioritise what it termed or perceived to be lower costs for consumers and referenced this duty in the context of ensuring a regulated business could finance its activities.[115] While the Utility Regulator clearly has a duty to protect consumers under the Principal Objective, the Financeability Duty is not a subsidiary consideration.[116] Instead, the correct approach is to further the consumer interest while "securing" financeability. Securing the regulated company's financeability, thereby discharging its Financeability Duty, is a necessary way in which the Utility Regulator furthers the Principal Objective, thus protecting the interests of consumers, both short and long term.

18.10 The Appellant met the Utility Regulator on several occasions after the publication of the Draft Determination to explain its concerns and to seek resolution, as explained in BT1. In the Final Determination the Utility Regulator declined to alter its position, concluding that based on its review of the Appellant's business capital requirements it did not consider it necessary (or in the interests of consumers) to allow any additional return:[117]

> *The Utility Regulator has concluded the existing RAB*WACC regulatory framework remains appropriate. Overall, the Utility Regulator has found insufficient grounds, based on its examination of the business's capital requirements, for allowing any additional return, whether in the form of allowances for contingent equity capital, intangible capital or a margin, over and above those elements in the RAB*WACC framework.*

18.11 The Appellant considers that the Utility Regulator's assessment as to whether a margin-based approach would secure its financeability was cursory and conclusory and therefore inadequate.

18.12 In the Final Determination, the Utility Regulator acknowledged SONI faced *"particular financing issues"*.[118] It sought to fix these issues by uplifting the pre-tax WACC from 5.42 per cent to 5.9 per cent. The Appellant explained that it considered this to be the wrong way to secure its

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114 Draft Determination, paragraph 247 **[NOA1/11]**.

115 See for example Approach Paper paragraph 2.5 **[NOA1/9]** and Draft Determination, paragraph 185 **[NOA1/11]**.

116 See Part III on Statutory Framework for further details.

117 Final Determination, Executive Summary, page 3 **[NOA1/12]**.

118 Final Determination, paragraph 365 **[NOA1/12]**.

financeability, being limited to addressing the Appellant's high operational gearing. Nonetheless, in the Decision Paper, the Utility Regulator confirmed its position that setting the WACC at a particular level solved the Appellant's financeability issues, explaining:[119]

> *…the UR recognises that SONI is an asset light business with a high level of operational gearing. As the SONI TSO business has a relatively small RAB the UR has decided to remain consistent with its approach for SONI and therefore will continue to use a pre-tax WACC.*

18.13 In light of its concerns that the Utility Regulator's approach was seriously flawed, the Appellant engaged both KPMG and Europe Economics to provide expert opinions concerning the adequacy of the Utility Regulator's approach to applying a regulatory framework capable of securing the Appellant's financeability. KPMG focuses in particular on why a margin-based approach is appropriate for the Appellant and Europe Economics examines the case for margins and also why uplifting the pre-tax WACC is not a credible solution to the Appellant's financeability problem.

(a) Assessment of the adequacy of the Utility Regulator's approach and KPMG's opinion

18.14 KPMG identifies that a simple RAB-WACC approach, although an effective way of determining profits for asset-heavy, capital intensive regulated networks without significant intangible assets, has certain limitations and can result in significant challenges when applied in the context of an asset-light business:[120]

> *In particular, the RAB-WACC framework is premised on the fact that the RAB of a regulated business is an accurate proxy for all the capital employed by the business and the scale of its operations and where the company's risks are highly correlated to capital-based activities. While this is likely to be the case for asset heavy network utilities, it is not the case for asset light businesses such as SONI.*

18.15 It was therefore inappropriate for the Utility Regulator to conclude that simply applying a traditional RAB-WACC framework to the Appellant without additional layers of return would enable it to secure the Appellant's financeability. As noted by KPMG:[121]

> *The UR did not consider that any additional layers of capital employed in the business other than the RAB required remuneration in order to ensure financeability. Effectively, it concluded that TSO business activities do not require alternative approach to determining the allowed profit. The analysis set out in this Report highlights reasons why this conclusion is not supported by the evidence and a robust evaluation process.*

18.16 In particular, the Utility Regulator should have put in place a framework that reflected the risks faced by the Appellant. In the Appellant's case, the risks to its business are largely driven by operational factors (opex risk and liquidity risk associated with pass-through costs) and factors that reflect its capital structure (operational gearing) rather than factors associated with financing and implementing of capital investment.

119 Decision Paper, paragraph 123 **[NOA1/18]**.

120 KPMG1, paragraph 1.1.9, **[MC1/1]**.

121 KPMG2, paragraph 2.26 **[MC1/2]**.

18.17 KPMG note that:[122]

> *A presumption that a firm's ability to earn profits should be exclusively linked by regulation to the extent of its capital investments in tangible assets is problematic for the following reasons:*
>
> - *It may encourage the firm to focus effort and resources on undertaking capital expenditure regardless of whether this generates value for customers;*
> - *It may encourage the firm to divert effort and resources away from activities that do not involve capital expenditure but generate value for customers;*
> - *It may expose the firm to risks that it is not well-placed to manage or accommodate, and/or create perverse incentives for stakeholders in the business;*
> - *It may result in the firm with a small expenditure on tangible assets being exposed to the risk of financial difficulties or even distress, which capital providers cannot accept; and*
> - *It may undermine dynamic efficiency, since entrepreneurial time and effort are not remunerated which limits the returns to innovation.*

18.18 The RAB-WACC model is not well suited to account for the scale of operational activity of a business if those activities are not related to the RAB. In effect, the greater the proportion of operational activity to the value of the RAB, the less effective the RAB-WACC approach is at providing adequate revenues to finance the business. This relationship can be illustrated by comparison with examples of regulated network businesses in terms of the size of RAB and turnover:[123]

Figure 7: Comparison of allowed equity return to opex

	Low	High	Central estimate
UK rail: network infrastructure	n/a	n/a	80%
Australian water	n/a	n/a	55%
Ireland gas: transmission and distribution	42.1%	51.9%	47%
UK distribution network operators	32.5%	58.9%	46%
UK water: WoCs and WaSCs	32.8%	45.3%	39%
NGET	n/a	n/a	33%
SONI (2015-2010, under margins)	9.3%	14.6%	12%
SONI (2015-2020, under RAB-WACC)	2.7%	6.8%	5%

[122] KPMG2, paragraph 3.2.8 **[MC1/2]**.

[123] KPMG2, paragraph 6.4.3 **[MC1/2]**.

18.19 The table at Figure 7 illustrates the difficulties faced by the Appellant in securing required returns based on its RAB because the expected profitability is largely driven by its operations and not by the return on capital invested in its limited tangible asset base. This means RAB*WACC is unlikely to generate sufficient revenues to fund the business. Under the RAB-WACC framework, profit is linked to the scale of investment activities in tangible assets, as opposed to the scale of business operations. Business activities that rely on operating costs, as opposed to investments, do not earn a profit under the RAB-WACC framework, unless the business can outperform on costs.

18.20 The Appellant provided contemporaneous evidence of these issues in support of the Business Plan and the Utility Regulator failed to have regard to these submissions. This included acknowledgement that while the RAB-WACC model is widely used and well understood, there are alternative approaches that are better suited for regulating asset-light businesses. There is no evidence that the Utility Regulator discharged its obligation properly to consider these alternatives.

18.21 An obvious alternative approach that the Utility Regulator should have considered is margin-based regulation, given that this approach is regularly applied to asset-light businesses. For example, KPMG notes that:[124]

> *The margin model is often used as a practical solution to the challenge of setting an allowed return where a business has little or no tangible assets with which to constitute a RAB. The requirement for a business – even one which does not possess tangible fixed assets – to earn a profit was alluded to previously; this requirement would not be met under a RAB-WACC framework in the context of such a business.*

18.22 KPMG were asked to conduct a detailed evaluation of how the RAB-WACC and margin regimes performed against a set of reasonable criteria. They conclude that:[125]

> *…from the evidence in other markets, we can infer that the margins-based framework results in a level of profit that is closer to the normal profit in a competitive market and more consistent with the opportunity cost. Furthermore, a RAB-WACC framework might not ensure that the firm provides important services that are not linked to significant investments in tangible assets.*
>
> *When these frameworks are evaluated against the selected criteria in SONI's case, the margins-based framework is at least as appropriate as the RAB-WACC framework in almost every respect, and is strongly preferable in several respects… Taken together, the margins-based framework is preferable overall in SONI's case*.

(b) Europe Economics' opinion as to the aptness of the Utility Regulator's approach

18.23 The Appellant commissioned an expert report from Europe Economics (which previously advised the CER on the treatment of similar matters for EirGrid) to provide a further independent view as to the appropriateness of applying the WACC*RAB regulatory framework for an asset-light business such as SONI. In AL1, Europe Economics notes that although SONI is *"unusual"* in being a regulated entity subject to a price cap that is asset-light, *"it is by no*

124 KPMG2, paragraph 5.3.3 **[MC1/2]**

125 KPMG2, paragraphs 1.1.19 – 1.1.22 **[MC1/2]**

means unique".[126] Consistent with the expert advice from KPMG, Europe Economics cites a range of regulatory precedents from sectors including retail energy, retail water, high speed rail and postal services as examples, noting that the approaches taken to regulate these sectors include *"both the traditional RAB-WACC approaches with certain pragmatic adjustments <u>and</u> approaches based on a regulated margins"* (emphasis added).[127] It was therefore entirely reasonable for the Appellant to have expected the Utility Regulator to consider a broad range of precedents, and it is likely that it did not.

18.24 Europe Economics concurs with KPMG that often the best approach for regulating asset-light companies and ensuring financeability is to adopt a margins approach, explaining:[128]

> *… there will be cases in which there is inadequate information available to provide a meaningful direct and objective estimate of the value of intangibles; insufficient evidence on which to base a working capital allowance or large elements of the business, likely to be associated with intangibles, to which working capital is not relevant; and insufficient data or insufficiently close comparators to use an operational gearing adjustment with any precision. In such cases, margins, though third-best in principle, may be best in practice.*

18.25 Europe Economics describes the Utility Regulator's view that its proposed uplift to the WACC would allow it to address any financeability concerns within the current framework as *"implausible"*.[129] Europe Economics justifies its view as follows:[130]

> *Absent the use of margins, estimation of intangible assets, adjustment of the WACC to take account of operational gearing differences, creation of additional elements to the cost stack such as a working capital allowance or a direct use of financeability metrics as the basis for setting a return allowance, modest add-ons to the WACC determined for an asset-heavy business in the same sector (e.g. calculating a TSO WACC as a TAO WACC plus an uplift) is very unlikely to be a pragmatically adequate means to address the issue of unobservable intangibles for fixed asset-light businesses…*

18.26 To support this conclusion, Europe Economics provides an illustrative example of two businesses in the same sector – one a fixed asset-heavy business for which there is a RAB and an observable WACC and the other a fixed asset-light business – which it designed for the purposes of assessing the Utility Regulator's decision. It assumes for the purposes of the example that it is correct to assign them the same WACC (6 per cent) and that only half of the assets of the asset-light business are observable i.e. the observable assets are £25 million but the true asset enterprise value is £50 million. In the example, the regulator seeks to correct this problem by uplifting the WACC by 0.5 per cent so it gets a 6.5 per cent WACC applied to its assets. This inadequately compensates the firm for the majority of its assets. Indeed, the only

126 AL1, paragraph 7.1.

127 AL1, paragraph 7.2.

128 AL1, paragraph 8.19.

129 AL1, section 9 "Why it is implausible that the proposed WACC uplift, offered by Uregni to allow for the impacts of thin capitalisation, provides a means to address the issue".

130 AL1, paragraph 9.1.

way to achieve this is to double the WACC to 12 per cent, a step most regulators would be reluctant to take. As Europe Economics explains:[131]

Modest uplifts of the scale regulators find pragmatically convenient to deal with other areas of uncertainty in the price control – of the order of 0.5 per cent – are simply not going to be sufficient if the issue is that much, if not most, of the asset base is not identified. The table below summarises this example…

	Fixed-Asset Heavy Business	*Fixed-Asset Light Business*
WACC (1)	***6%***	***6%***
Observable assets (2)	***£50m***	***£25m***
Return on observable assets (1) x (2)	***£3m per annum***	***£1.5m per annum***
Total assets (3)	***£50m***	***£50m***
Return on observable assets including 0.5% uplift	***N/A***	***£1.63m per annum***
WACC required to provide £3m per annum return	***6%***	***12%***

18.27 Europe Economics states that a better and more transparent approach, if it were feasible, would be to set the RAB at its correct value (in this case £50 million) rather than uplifting the WACC to 12 per cent. However, where businesses have a significant proportion of intangible assets it is difficult to assign an accurate RAB with any certainty. In that context, attempting to apply a more-or-less arbitrary WACC uplift to a highly uncertain RAB could, as Europe Economics puts it *"result in very large over- or under-remuneration"*.[132]

18.28 Europe Economics repeats the example by tailoring it to the Appellant's business and examining the position with or without a side RAB. The report states:[133]

On either basis, it would seem that the WACC uplift provided by the Utility Regulator is likely to be too small.

18.29 Europe Economics concludes that the Utility Regulator's "quick fix" fails to secure its financeability because it under-represents the true value of its assets (meaning investors do not receive a fair return on those assets) explaining:[134]

131 AL1, paragraph 9.4 and Figure 9.1.

132 AL1, paragraph 9.5.

133 AL1, paragraph 9.13.

134 AL1, paragraph 10.5.

From the information provided to us, SONI appears to be an asset-light business with a relatively high proportion of intangible assets. It is thus a natural candidate for a margin approach to be considered. The Uregni method of providing an asset beta uplift appears to us to be unlikely to have been adequate, given certain structural similarities between the SONI business and that of EirGrid and our calculations suggesting that the Uregni uplift has accounted for only of order one eighth to one third of the required additional return allowance.

(c) Summary and conclusion

18.30 In summary, the Utility Regulator failed to give due and proper consideration to employing a suitable regulatory framework and therefore due consideration to the discharge of its functions. Evidence from KPMG and Europe Economics supports the conclusion that the RAB*WACC approach employed by the Utility Regulator affords the Appellant insufficient funds to finance its activities and provide an inadequate return to investors. Indeed, the Utility Regulator recognised that it had not fully resolved the Appellant's financeability issues. It sought to assuage the Appellant's concerns by inserting a statement in the Final Determination confirming that its decision to retain the existing regulatory framework "*does not fix a precedent and the issue will be fully considered again at the next price control*".[135] Given the unsatisfactory nature of the framework it is unclear why the Utility Regulator did not take the opportunity to fully consider the issue as part of the Price Control review.

19 Error 1(b): the Utility Regulator's limited and inadequate financeability assessment was subject to material errors

19.1 As explained above, the Appellant does not accept that the Utility Regulator applied an appropriate framework. In addition, the Appellant considers that the Utility Regulator failed to conduct an adequate assessment of its financeability given its limited focus on applying financial ratio tests to RAB investments. It also made errors when conducting its assessment.

19.2 In its Final Determination, the Utility Regulator acknowledged that its initial financeability assessment had been inadequate, stating:[136]

…the Utility Regulator has decided that it would add value to consider a wider range of approaches to the WACC from the relatively standard one which featured in the Draft Determination.

19.3 The wider range of approaches included uplifting the WACC as a means to address the Appellant's high operational gearing – an approach borrowed from the CMA's provisional findings in the Energy Market Investigation. It is not evident what analysis the Utility Regulator conducted on this issue. The Utility Regulator summarised its approach stating:[137]

As a cross-check on these calculations, the Utility Regulator has looked at the recent work of the CMA in its Energy Market Investigation on the WACC for a retail energy

135 Final Determination, Executive Summary, page 3 **[NOA1/12]**.

136 Final Determination, paragraph 365 **[NOA1/12]**.

137 Final Determination, paragraph 365 **[NOA1/12]**.

supply business. As part of this work the assumed 100% equity financing and its range of assumptions produces a pre-tax WACC range of 4.75-6.75%. […] Having considered the updated analysis considering the CMA work presented above the Utility Regulator has decided to apply a pre-tax WACC of 5.9% (adjusting to changes in the corporation tax rate) for SONI.

19.4 When the CMA examined these matters in the context of the Energy Market Investigation it was not concerning itself with *securing* financeability. By contrast, the Financeability Duty requires the Utility Regulator to *secure* the Appellant's financeability. Moreover, this is not just the theoretical financeability of a generic asset-light company but rather it must take into account the Appellant's specific characteristics.

19.5 The Appellant submits that this last minute adjustment or "cross-check" was insufficient to remedy the defects in the Utility Regulator's financeability assessment. At no point did the Utility Regulator explain why the isolated adjustment of uplifting the WACC secured the Appellant's financeability overall. There is no evidence in the Final Determination that the Utility Regulator had progressed its financeability assessment, as it did not conduct any equity financeability tests, or give proper consideration as to the Appellant's financial resilience in the event plausible downside shocks occurred. This is despite the Utility Regulator stating that it had reviewed the Appellant's response to its Draft Determination and had used the intervening ten month period:[138]

…to carry out further analysis, consider the latest regulatory evidence and discuss the matters further with consultants.

19.6 No details are provided as to what further analysis was undertaken or which particular evidence was considered. Indeed, the Appellant was not even made aware that the Utility Regulator had engaged with consultants, meaning it had no opportunity to explain its position. The consultant's findings have never been disclosed.

19.7 As explained in BT1, the lack of transparency is particularly frustrating given the Appellant's repeated attempts to engage with the Utility Regulator to explain its position. Given the first time the Utility Regulator's use of consultants was mentioned was in the Final Determination, the Appellant can only conclude that the Utility Regulator had closed its mind to the issue other than for a final brief sense check, which the Appellant submits cannot have been fully considered. As outlined in BT1, the Appellant would have welcomed an opportunity to engage with the consultants.

19.8 Given its concerns, the Appellant commissioned KPMG to examine the robustness of the Utility Regulator's financeability assessment.

(a) Adequacy of the Utility Regulator's financeability assessment and KPMG's opinion

19.9 The Utility Regulator undertook a limited and inadequate financeability assessment, focusing on a narrow set of financial metrics and assuming solely a best case scenario with no consideration of downside outcomes. This fell considerably short of a robust financeability

138 Final Determination, paragraph 268 **[NOA1/12]**

assessment and stemmed from its failure to set out an appropriate framework for securing the Appellant's financeability.

19.10 KPMG's financeability report supports this view, stating that:[139]

> *[T]he UR's approach to assessing financeability … is not appropriate for SONI and not robust—it falls short of industry standards, lacks rigour and depth, is incomplete, and, in some places, inconsistent. This conclusion is based on the following key observations:*
>
> - *First, the financial projections used for UR's financeability analysis as inputs appear to be biased upwards and inconsistent between UR's financial model and the FD.*
> - *Second, UR's financeability analysis lacks appropriate focus and analysis of the key financial metrics.*
> - *Third, the metrics the UR has actually calculated provide at best a highly incomplete description of SONI's financial position—they do not consider all layers of capital and do not correspond to the nature of the SONI business.*
> - *Fourth, there is absence of robust benchmarks for the financial metrics or their interpretation, which is necessary to conclude on SONI's financeability.*
> - *Fifth, the UR does not consider scenarios other than the base case, which means that SONI's risk exposure is not considered.*
> - *Finally, other critical factors impacting financeability such as the design and transparency of the regulatory framework or the scale and the nature of the financing required are not considered by the UR at all.*
>
> *Therefore [the] UR's analysis cannot be considered to be a meaningful test of whether SONI is likely to be able to finance its activities and planned investments over the course of the price control.*

19.11 KPMG explain that a financeability assessment typically involves three core components.[140]

(a) First, the regulator should conduct financeability tests based on the company's business characteristics, its Business Plan and a realistic and internally consistent set of assumptions about financial markets and investors' expectations. KPMG suggests that such tests are a vital part of the regulator's role in discharging its financeability duty by ensuring the company is financeable.

(b) Second, the regulator should apply both debt and equity financeability benchmarks. KPMG explains that in doing so the regulator must consider the maximum acceptable level of financial risk and how that is reflected in the tests; the extent of required headroom in the company's financial position given the nature of its operations and the

[139] KPMG1, paragraphs 1.24 and 1.25 **[MC1/1/5-6]**

[140] KPMG1, paragraph 3.1.12 **[MC1/1/16-17]**

risks that it faces; and the existence of financial constraints and investors' considerations, included those which are likely to be present in the real world.

(c) Third, the regulator, where it identifies a financeability issue, should form a view as to what actions might be appropriate to secure that the licence holders can finance their functions including ensuring financial sustainability in the long-term.

19.12 In KPMG's expert opinion, if the financial assessment omits any of these core components then it will not be meaningful.

19.13 Taking the first component, financeability tests, the tests conducted by the Utility Regulator were not appropriately tailored to the Appellant's business characteristics:[141]

> *The differences between SONI's business characteristics and those of traditional utilities imply that the standard financeability assessment approach that is applied to traditional utilities is neither appropriate nor sufficient in this context to ensure that SONI can finance its functions.*

19.14 Further, the Utility Regulator acknowledges that it is in fact not explicitly assessing financeability through testing financial ratios and states that "*limited weight should be placed on these ratios given that the amount of debt finance that the business utilises is a matter for SONI alone*".[142] KPMG comments that in its failure to conduct a robust analysis of credit metrics and other financial ratios, the Utility Regulator's approach is at variance with typical regulatory practice: [143]

> *This approach stands in contrast to those adopted by other UK regulators, which explicitly assess financeability.*

19.15 The Utility Regulator also failed to ensure that its financeability tests were forward-looking so as to take into account the projected evolution of risks over the next control periods. This was particularly important in the Appellant's case because the risks it faces are increasing over the Price Control. Finally, the Utility Regulator failed to consider all sources of capital employed, focusing only on the capital reflected in the RAB.

19.16 As regards the second component, the Utility Regulator failed to give more than scant attention to equity financeability tests despite the clear importance of equity for financing the business given the Appellant's particular features and circumstances, in particular its low debt capacity driven by a low RAB and exposure to risk and uncertainty under the Final Determination. Related to this, its failure to consider the Appellant's financial resilience is a significant omission. It should have paid particular regard to the level of financial headroom and run downside scenarios to assess what happens in the event one or more of the risks faced by the Appellant actually crystallises.

19.17 KPMG explains that consideration of financial resilience to downside shocks is best practice and can be observed in other regulators' price control determinations. For example, KPMG

141 KPMG1, paragraph 4.2.1 **[MC1/1/24]**

142 Final Determination, paragraphs 272, 316 **[NOA1/12]**

143 KPMG1, paragraph 3.2.10 **[MC1/1/19]**

highlights that Ofgem explicitly considers resilience to plausible downside scenarios as part of its approach to its finance duty: [144]

> *Based on their duty, Ofgem then expands on their approach throughout the draft and final determinations to ensure a robust assessment is undertaken. For example, Ofgem considers in its determinations[145] how "resilient DNOs would be to plausible downside scenarios" to create a safe investment environment. The UR does not consider any downside scenarios or potential shocks.*

19.18 For the Appellant as an asset light company with limited ability to manage financial risk the resilience to or financial headroom to withstand reasonable downside shocks is particularly important, a point emphasised by KPMG its assessment of the Utility Regulator's approach:[146]

> *The level of financial headroom assumes a particularly important role in SONI's case, given the size of SONI's operations compared with the value of its current RAB and the types of risk to which SONI is exposed. A corollary of this is that scenarios that depart from the projected 'equilibrium' financial trajectory for the business should be explicitly considered in order to ensure that SONI is financeable in the light of potential risks given significant business uncertainties.*

19.19 Finally, as regards the third component, the Utility Regulator's inadequate assessment failed to identify the Appellant's financeability problems. It did not therefore consider or propose any mitigating action. As explained in AS1, the banks have indicated that they are not prepared to lend to the Appellant without a cross-guarantee or Letter of Comfort.

19.20 As a consequence of these factors, the Utility Regulator's financial assessment was unduly limited and did not constitute a meaningful assessment of the Appellant's financeability. Its conclusion that the Decision secured the Appellant's financeability was therefore unsound.

(b) Errors in the Utility Regulator's financial assessment

19.21 The Utility Regulator made several errors in the limited financeability assessment that was undertaken. These included a failure to remunerate all capital within the business by not funding the Appellant for the cost of the Parent Company Guarantee (PCG) and errors in its modelling, benchmarking, and debt financeability tests.

(i) <u>Failure to remunerate all layers of capital – the PCG</u>

19.22 All capital employed needs to be identified and remunerated if the Appellant is to have the right amount of cash to finance its activities and if the correct level of return is to be allocated to the Appellant. This is supported by KPMG's financeability report, which states:[147]

> *The importance of remunerating all capital employed in the business and ensuring that profitability corresponds to the scale of business operations is consistent with the way in*

144 KPMG1, paragraph 3.2.6 **[MC1/1/18]**

145 Ofgem, "RIIO-ED1: Final determination for the slow-track electricity distribution companies – Overview", 28 November 2014 (https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_overview_-_updated_front_cover_0.pdf)

146 KPMG1, paragraph 4.2.6 **[MC1/1/25]**

147 KPMG1, paragraph 9.2.3 **[MC1/1/104]**

which investors approach the valuation of asset light businesses. The attractiveness of asset-light businesses for investments is highly sensitive to the expected remuneration on all tangible and intangible assets and for all economic activities.

19.23 The Utility Regulator has not remunerated the Appellant for having the PCG in place despite this being a licence requirement. Condition 3A of the Licence requires the Appellant to procure an undertaking from EirGrid, in a form approved by the Utility Regulator, so as to ensure that the Appellant has adequate financial and non-financial resources to perform its obligations and meet any liabilities under the Licence. In fulfilment of this requirement, EirGrid provided a £10 million PCG at the time of the acquisition of the Appellant. This provides a significant contingent capital arrangement in addition to the £12 million revolving credit bank facility that the Appellant currently has in place, as explained in AS1.

19.24 The failure to remunerate the Appellant for all of the capital employed reduces the Appellant's ability to finance its activities and to attract further capital.

19.25 The Utility Regulator's reason for not remunerating the PCG under the Licence is that an identical licence obligation applies for SEMO and the Appellant is therefore remunerated for having the PCG under this licence. Effectively, and erroneously, it is concerned about "double recovery".

19.26 The Utility Regulator relies on its SEM Committee's decision in support of its reasoning. This suggests that the SEM Committee only remunerated the provision of working capital under the (then in force) 2013-2016 SEMO price control having received assurances that the Appellant was not remunerated for it under any other price control.[148]

19.27 However, the TSO Licence requirement for the PCG is separate from the SEMO Licence requirement, reflects distinct risks as explained in AS1, and should be remunerated separately. The SEMO allowance was not set with respect to the TSO licenced business activities and risks, and therefore does not remunerate SONI for the contingent capital required to carry out business activities in relation to the TSO price control. Moreover, the risks underlying the Appellant's business under its SEMO Licence are separate and distinct from the risks underlying the Appellant's business under its TSO Licence. As explained in KPMG1, KPMG has undertaken analysis which suggest that the appropriate level of remuneration for the requirement to have the PCG in place in so far as it covers the independent and separate risks under the TSO Licence is £310,000 per annum or £1.550 million over the course of a five-year Price Control.[149]

(ii) Errors in financial modelling

19.28 As discussed in AS1, the financial model fails to reflect the projects set out in the Final Determination. For example, differences between the model and the Final Determination can be identified with respect to non-building Capex figures, pre-construction asset figures and

[148] Final Determination, paragraph 296. In fact, it would not have been possible for the Appellant to be remunerated for risks arising under its Market Operator licence, in any other licence, given that the Utility Regulator's duty is to secure the financeability of each licence holder on a separate basis and without cross subsidy.

[149] KPMG1, section 6.4 **[MC1/1/56-57]**

professional fees.[150] In its analysis, KPMG found evidence of internal inconsistencies within the financial model, noting:[151]

> *There are also other issues with the UR's financial model which render its financeability analysis not robust and most likely biased. In particular, positive incentive payments are assumed to be part of the base case for the financeability assessment. By assuming positive incentive payments, the revenue and hence the financial headroom are assumed to be higher than expected in the base case, which means that the financial ratios are artificially inflated.*

19.29 Further, the financial model does not reflect the notional financial structure assumed by the Utility Regulator in the Final Determination. This creates a discrepancy between the gearing assumed in the WACC (and hence the quantum of debt that is being rewarded) and the level of debt (and hence the cost of debt) assumed in the model.

19.30 It is important to note that the Utility Regulator's model has limited functionality, and does not include mechanisms to sensitise key variables and develop downside scenarios. This suggests that the Utility Regulator has not explicitly tested the Appellant's resilience to shocks and corroborates findings above in respect of the Utility Regulator's financial assessment.

19.31 KPMG has also identified a number of basic formula-driven in the Utility Regulator's model, which are set out in Appendix 1 of KPMG1, including errors in the calculation of RAB depreciation on 2009 additions and interest paid in 2015/16.[152] These errors and inconsistencies cast doubt on the robustness of the financial model as a tool for determining the Appellant's financeability.

(iii) Errors in financial benchmarks

19.32 A further factor demonstrating the inadequacy of the Utility Regulator's approach was the fact that it failed to apply appropriate benchmarks for the Appellant's business. While the Utility Regulator has published projections of certain financial ratios, there is no evidence that it sought to compare these ratios to appropriate benchmarks or provided any interpretation of what these projections might imply. Given that the Utility Regulator has a duty to secure the Appellant's financeability, it is reasonable to expect that it would have undertaken its own analysis in respect of appropriate benchmarks for the Appellant's business.[153] This would include an assessment of how the thresholds that are appropriate for the Appellant compare with the corresponding thresholds used for asset-heavy utilities. This standard component of any financeability test is missing, suggesting that the Utility Regulator did not conduct a robust assessment and that its conclusion – that the Appellant's business was financeable – is not meaningful.

(iv) Errors in the debt financeability assessment

150 KPMG1, paragraph 7.4.3 **[MC1/1/66]**

151 KPMG1, paragraph 7.4.4 **[MC1/1/66]**

152 KPMG1, Appendix 1 **[MC1/1/127-128]**

153 KPMG also made this observation – see paragraph 7.4.9 of KPMG1 **[MC1/1/67]**

19.33 KPMG consider that the Utility Regulator conducted a *"very limited"*[154] debt financeability analysis. KPMG considers that the Utility Regulator's interest cover calculations were based on a set of unrealistic and optimistic assumptions, thereby, increasing the amount of cash from operations relative to the projections and improving the ratio and not considering working capital facilities, effectively ignoring a substantial part of debt financing used by the Appellant.[155]

19.34 The Utility Regulator failed to conduct a reasonable financeability assessment that addressed whether or not the Appellant could finance its activities. Reliance on projections with unrealistically positive assumptions cannot convey any information about the Appellant's ability to access capital markets or about its financial resilience in the context of reasonably anticipated downside shocks. This provides further evidence that the Utility Regulator was wrong to conclude that the Price Control secured the Appellant's financeability.

(c) Summary and conclusion

19.35 The Utility Regulator's financeability assessment failed to apply a robust methodology and to apply appropriate cross-checks. It took a cursory and conclusory approach to assessing the Appellant's financeability, placing insufficient weight on the circumstances faced by the Appellant for the upcoming Price Control. The analysis therefore lacks the rigour of a proper financeability assessment and it cannot be said that the Utility Regulator discharged its Financeability Duty. As noted by KPMG in summary:[156]

> *Together, these observations suggest that the UR does not appear to have undertaken a sufficiently thorough assessment to conclude that the FD will allow SONI to finance its activities on a stand-alone basis. Therefore, UR's analysis cannot be considered to be a meaningful test of whether SONI is likely to be able to finance its activities and planned investments over the course of the price control.*

20 Error 1(c): the Utility Regulator failed to conduct a complete financeability assessment which – had it done so – would have demonstrated that the Appellant is not financeable

20.1 The Appellant instructed KPMG to conduct its own thorough financeability assessment applying the tests the Utility Regulator should have conducted but failed to do so.

20.2 In particular, KPMG was asked to examine whether it considered that the Appellant is financeable under the Price Control from an equity perspective: first, by comparing its expected margins to a reasonable benchmark; secondly, by assessing whether the Appellant is exposed to a level of risk that it can reasonably be expected to manage; and thirdly, by assessing whether the allowed equity returns set out in the Final Determination are adequate in light of certain risks faced by the business.

20.3 The margin-based financeability assessment is set out in KPMG1, a summary of their findings is presented in the following section.

154 KPMG1, paragraph 7.7.1 **[MC1/1/75]**.

155 KPMG1, paragraph 7.7.1 **[MC1/1/75]**.

156 KPMG1, paragraph 1.25 **[MC1/1/6]**

20.4 KPMG3 explains that a pre-condition for equity financeability is that investors can expect, *on average*, to earn the equity return required.[157] Where the price control is set such that the mean expected return is below this allowed return, the business will not be able to attract capital and hence will not be financeable. The key measure for KPMG, therefore, in conducting its assessment was whether or not the expected returns as provided for under the Final Determination were sufficient to enable the Appellant to attract capital and have sufficient cash to finance its activities.

20.5 In conducting its analyses, KPMG assumed a base case whereby all allowance errors identified in Part IV had been rectified.[158]

(a) Margin benchmarking analysis

20.6 A significant flaw in the Utility Regulator's assessment was the failure to conduct a margin benchmarking analysis. In the Appellant's case, as an asset-light business, focusing on RAB*WACC systematically yields revenue figures which are inadequate for the Appellant's purposes. This is why margin benchmarking is a standard approach employed by rating agencies when assessing the profitability and returns from asset-light businesses and indeed by the businesses themselves.[159]

20.7 KPMG explain that applying a margins assessment is entirely reasonable and appropriate,[160] and that there are several examples of regulators assessing profitability and margin-based financeability metrics.[161] In particular, the CMA has used margins as a basis for benchmarking returns and profitability in the context of both regulatory appeals and market investigations. For example, in the Energy Market Investigation, the CMA supported the use of margins as a useful tool for assessing profitability, alongside capital-based metrics such as ROCE recognising the need to undertake a range of profitability measures given uncertainty about measurement of the capital base in reaching a view on firms' financial performance.[162] The Utility Regulator referenced the CMA's work in the Energy Market Investigation in the Final Determination despite not conducting a margins analysis.

20.8 In order to assess the Appellant's equity financeability, KPMG compare the expected margins under the Financial Determination with what it considers to be an appropriate margin benchmark. In choosing an appropriate margin metric, KPMG consider a range of possible measures before determining that EBIT is the most appropriate because:[163]

(a) it does not require direct adjustments to be made to reflect the degree of pass-through costs, as is the case with gross margins (although care must still be taken when comparing between firms with different levels of pass-through costs);

157 KPMG3, paragraph 3.2.2 **[MC2/1/11]**

158 In the event the allowances errors are not remedied in whole or in part the financeability issues identified in this section will be exacerbated as explained in Part V.

159 KPMG1, section 9.2 **[MC1/1/104-106]**.

160 KPMG1, section 9.4 **[MC1/1/107-109]**.

161 KPMG1, section 9.7 **[MC1/1/115-121]**.

162 KPMG1, paragraphs 9.4.8-9.4.10 **[MC1/1/108]**.

163 KPMG1, section 9.5 **[MC1/1/109-110]**.

(b) by excluding depreciation and amortisation, it avoids issues associated with the comparability and interpretation of capital repayment charges across different sectors, as is the case with EBITDA margins;

(c) it has clear definition, is easily comparable across sectors/companies and the required data is readily available; and

(d) there is clear regulatory precedent for the use of the EBIT margin metric in evaluating the adequacy and financeability of allowed revenues for regulated utilities.

20.9 KPMG employ five key criteria in assessing which companies represent the most appropriate comparators to inform the benchmark level of EBIT margin that might be appropriate for the Appellant. Relevant comparators were deemed to be those companies with a relatively high asset turnover; where the RAB represents a relatively limited proportion of total capital employed; with a similar level of capital intensity; undertaking a similar scale of operations to the Appellant; and those which have a proportion of pass-through costs.[164]

20.10 The forecast margins that formed the basis of KPMG's comparison were based on one of two scenarios:

(a) a scenario based solely on the Final Determination (the **Final Determination Model**); and

(b) a scenario which includes revenues associated with the key outputs to be delivered during the Price Control (i.e. I-SEM, network planning and DS3) (the **Business Plan Model**).

20.11 The results of KPMG's benchmarking analysis indicated that margins on controllable revenues of 10–14 per cent provide a useful comparator for the Appellant's profitability on controllable costs.[165]

20.12 KPMG also benchmarked margins on total revenues, recognising some of the difficulties in doing so. The results of KPMG's benchmarking analysis indicate margins on total revenues of 1.5 - 3 per cent represent an appropriate comparator.

20.13 In KPMG's base case assessment (i.e. excluding any credible downside scenarios) for the Final Determination Model margins both on controllable revenue and total revenue were below the appropriate thresholds for the Appellant for the majority of the period as demonstrated in Figure 8 below:[166]

[164] KPMG1, paragraph 9.6.1 **[MC1/1/110]**.

[165] KPMG1, paragraph 9.6.15 **[MC1/1/114]**.

[166] KPMG1, paragraph 9.10.1 **[MC1/1/125-126]**.

Figure 8: SONI forecast EBIT margins under the Final Determination, 2015-2020

	2015/16	2016/17	2017/18	2018/19	2019/20	Average	Target
EBIT margin on controllable revenue with accounting depreciation	16.5%	3.1%	5.4%	9.9%	8.2%	8.6%	**10-14%**
EBIT margin on total revenue with accounting depreciation	2.6%	0.4%	0.6%	1.1%	0.9%	1.1%	**1.5-3%**
EBIT margin on controllable revenue with regulatory depreciation	2.5%	2.2%	2.1%	2.3%	2.0%	2.2%	**10-14%**
EBIT margin on total revenue with regulatory depreciation	0.4%	0.3%	0.2%	0.3%	0.2%	0.3%	**1.5-3%**

20.14 The results indicate that in almost all years of the upcoming control, the level of EBIT margin earned by the company (highlighted rows) is significantly lower than the benchmark level. The results are sensitive to the depreciation assumed in the calculation (i.e. regulatory or accounting depreciation). The regulatory depreciation is in the Appellant's view the more appropriate figure to use in this calculation, since it is the regulatory depreciation that is assumed by the Utility Regulator to be the cost of maintenance and it is derived from the Utility Regulator's regulatory framework rather than accounting requirements.

20.15 The only year in which the EBIT margin is above the benchmark is 2015/16 in the case that the accounting depreciation is used. This is driven by the recovery of the final year of regulatory deprecation on historic long life RAB (pre-2007 assets). In subsequent years the ratios improve as significant investment is expected for I-SEM and DS3 System Services but these are temporary uplifts as these assets remain as RAB for a short period of time.

20.16 As explained in Section 15 above, and further discussed in AS1 when the WACC RAB framework is compared to a benchmarked EBIT margin of 11% of controllable costs, consistent with that recommended by KPMG and applied in a manner consistent with that set out in KPMG's report,[167] the Appellant's investors are subject to a further shortfall of £5.336 million[168] under the Decision.[169] This means that the business is not financeable as explained by KPMG:[170]

> *SONI's average EBIT margin on both net revenue and total revenue for the period both lie below the benchmark in all years except 2015/16. This means that the business is not*

167 KPMG1, section 9 **[MC1/1/103-126]** and KPMG2 **[MC1/2]**
168 This is after adjusting for the binary error through the Utility Regulator's exclusion of provision of remuneration for the PCG.
169 In AS1, Aidan Skelly discusses the differences between the Final Determination and the Business Plan.
170 KPMG1, paragraph 9.10.3 **[MC1/1/126]**.

financeable in the sense that it would not be able to meet investors' expected returns for margins given SONI's business characteristics.

(b) Adequacy of equity returns

20.17 KPMG was instructed to examine whether the allowed equity returns set out in the Final Determination are adequate in light of certain risks faced by the Appellant in the Price Control Period.

20.18 The Appellant provided KPMG with both its view of likely expected outcomes and downside scenarios for testing based on its risk exposure. The scale and types of risk which the Appellant faces are explained in detail in AS1.

20.19 KPMG analyse the expected returns with a focus on (i) the inherent uncertainty of capital spend on network projects and the asymmetry of the regulatory treatment of these costs under the Dt mechanism; and (ii) the non-remuneration of the £10 million Parent Company Guarantee required under the Appellant's licence.

(i) <u>Analysis of expected returns</u>

20.20 KPMG highlights the importance of considering expected returns in the context of equity financeability:[171]

> *A key driver of equity financeability is also that investors can expect, <u>on average</u>, to earn the equity return allowed by the regulator. Where a price control is set such that mean expected returns are significantly below this allowed return, the business will not be able to attract capital and hence will not be financeable.* (Emphasis added)

20.21 KPMG's approach to addressing this question was as follows:[172]

> *Where a regulated business is subject to risks that are not reflected in the allowed revenues (i.e. where the allowed revenues are not equal to expected cash flows because they do not fully take into account downside risks) and are also not controllable (i.e. cannot be mitigated by management of the business), then the allowed return based on the CAPM framework will underestimate the required equity returns.*
>
> *Of particular relevance is the case where the non-systematic risks to which a company is exposed exhibit significant negative mean values. In this situation, the allowed return estimated using CAPM will under-compensate shareholders for the risks that they bear. The analysis in this Report demonstrates that SONI is exposed to risks that exhibit this profile, and estimates the gap between the allowed return and the expected return that this implies.*

20.22 <u>Network project risk scenario – expected returns</u>: In the Appellant's view, as set out in AS1 and further supported by the Jacobs Report, providing an estimate of efficiently incurred pre-construction asset costs is not straightforward. This is the phase of the project lifecycle which is

171 KPMG3, paragraph 1.39 **MC2/1/6]**

172 KPMG3, paragraph 2.9 **[MC2/1/9-10]**

most uncertain in terms of time and cost. In particular, there is a much greater likelihood that unforeseen costs will arise than that costs will be underspent. This is compounded by the fact that network project spend is subject to a cap rather than a symmetric risk sharing mechanism, meaning outperformance is impossible but underperformance likely.

20.23 The inherent uncertainty around estimation of network project capital spend and the asymmetry of its regulatory treatment under the Final Determination implies a significant expected loss to the Appellant. Estimating this is not straight forward. As noted by Aidan Skelly:[173]

> *This likelihood or expected non recovery represents a probabilistic assessment of potential scenarios which result in a loss of revenues or non-recovery occurring. It is recognised that this requires detailed information on the probability distribution of possible outcomes, which is not straightforward to ascertain for projects of the nature that SONI is undertaking. Moreover, it also requires clarity on the basis on which the Utility Regulator will set the cap beyond which SONI will be exposed to the risk of non-recovery, clarity we simply do not have.*

20.24 It is expected, for the purposes of this analysis, that the value of the Appellant's other incentives is zero: all other aspects of the regulatory framework are assumed to be fully symmetric. It is however noted that in the Appellant's view there is a further expected loss arising from other costs that are subject to the Dt mechanism, as set out in AS1, which would be in addition to the expected return on network projects assessed in this section.

20.25 Impacts on expected equity return (as measured by the RORE metric outlined previously) are estimated based on downside scenarios adjusted for the probability that these risks materialise. The Appellant's expected return is calculated by assigning probabilities to two scenarios: the base case (where the Appellant earns the allowed return in each period) and the network planning under-recovery scenario where the Appellant incurs network planning costs that are 15 per cent higher than the cap in every year of the forecast period.

20.26 The impact on the base case allowed RORE in the networks project risk scenario adjusted for expected returns is set out in Figure 9 below, based on a 25 per cent probability of 15 per cent non-recovery of forecast network project costs under the Business Plan scenario. This is consistent with the scale of potential non-recovery assumed by Aidan Skelly in AS1.

173 Paragraph 124, AS1 **[AS1/1]**

Figure 9: Impact of the projected outturn RORE in the networks project risk scenario

RORE (%)	2015/16	2016/17	2017/18	2018/19	2019/20	Average
(A) Base case (75% probability)	7.6%	7.6%	7.6%	7.6%	7.6%	*7.6%*
(B) Network Planning risk (25% probability)	-2.0%	-4.2%	-1.0%	2.4%	1.5%	*-0.7%*
(C) Expected RORE	5.2%	4.7%	5.5%	6.3%	6.1%	*5.5%*
(D) Shortfall in expected RORE (= (A) – (C))	2.4%	3.0%	2.1%	1.3%	1.5%	***2.1%***

20.27 An expected RORE of 5.5 per cent, which equates to a 210bps or 25 per cent shortfall in the expected (i.e. on average) return on equity compared to the Utility Regulator's assessment of required return. The Utility Regulator's assessment of required return, does not in itself does not deliver market based EBIT margin benchmarks and is materially lower than the allowed returns required by providers of equity capital. This calls into question whether the Appellant is financeable from an equity perspective. Equity investors that expected on average to earn 210bps less than their required return would not typically be willing to invest capital in the business.

20.28 In absolute terms, a 25 per cent probability of a 15 per cent shock equates to a reduction in allowed returns under the Business Plan of £700,000 million over the control period, or an expected reduction in shareholder returns of approximately £150,000 per annum. This is consistent with Aidan Skelly's assessment as set out in Figure 4 which demonstrates the shortfall in expected returns under the Decision. In addition, Aidan Skelly considers a similar potential scale of non-recovery associated with Dt, and identifies a further shortfall of approximately £800,000 as a result (also shown in Figure 4). Taken together this represents a significant shortfall associated with the asymmetric risk profile accorded to the Appellant under the Decision.

20.29 Based on analysis of in particular network project risks in expected terms, KPMG finds that: [174]

> *The FD does not enable SONI to earn its required return on equity in mean expected terms. The extent of the shortfall (c200bps) is likely to pose a challenge for SONI to access equity capital under the same risk assumptions, which in turn raises concerns about financeability of equity under the FD, given the nature of SONI's TSO business activities.*

20.30 This is even before the Dt risk – which has similar characteristics and properties – as considered by Aidan Skelly. The magnitude of the shortfall in returns that emerges would have negative implications for equity investors' willingness to commit capital to the business. As highlighted in AS1, EirGrid as investor in the Appellant would be reluctant to commit further

[174] KPMG 3, paragraph 1.5 **[MC2/1/1]**

capital to the Appellant under these circumstances, particularly given the non-remuneration of equity capital already committed to the Appellant in the form of the PCG:[175]

> *All of this puts the equity holders of SONI in a position where continued support for SONI may not be forthcoming should equity requirements arise.*

20.31 The asymmetric risk profile to equity investors is one of the key risks highlighted by EirGrid as explained in FS1.[176]

20.32 In this context, it is critical that the analysis presented above does not include all capital committed to the business by EirGrid. In particular, as explained in AS1 and FS1, the Appellant's £10 million PCG is part of the licence requirements and represents capital committed to the business and is not remunerated for risks associated with TSO activities. It is therefore reasonable, as a sensitivity, to include this within regulated equity within the RORE calculation and examine the impact.

20.33 First, the impact of the including the £10 million PCG in the base case as a sensitivity (excluding the impact of scenarios to reflect the Appellant's risk exposure) is considered, as shown in Figure 10 below.

Figure 10: Impact of including £10 million PCG in base case

RORE (%)	2015/16	2016/17	2017/18	2018/19	2019/20	Average
SONI business plan	7.6%	7.6%	7.6%	7.6%	7.6%	**7.6%**
SONI FD case adjusted for PCG	1.9%	1.6%	1.5%	1.6%	1.6%	**1.7%**
SONI business plan adjusted for PCG	2.2%	2.4%	3.5%	4.0%	3.8%	**3.2%**

20.34 When this is looked at the RORE figures are significantly below that assumed to be required by the Utility Regulator. In the context of the Appellant's low RAB, the non-remuneration of committed equity capital has a material impact on expected investor returns and the Appellant's ability to secure financing from providers of equity capital over the forthcoming control period.

20.35 It is important to consider this potential shortfall in the context of the Appellant's inability to secure funding from banks. Whilst the Appellant notes that this shortfall is likely to constitute an over-estimate of the expected shortfall in RORE to the extent that the £10 million PCG is not fully committed capital, it is a plausible sensitivity as in practice the PCG will need to be called upon where the Appellant is unable to secure debt financing to its manage liquidity exposure. As highlighted in AS1, debt providers are currently unwilling to provide lending to SONI based on the Final Determination.

20.36 In addition, it is important to consider the impact of non-remuneration of committed equity capital in the expected scenario set out above, where it is assumed in the central case that

175 AS1, paragraph 34. **[AS1/1]**

176 FS1, paragraph 48. **[FS1/1]**

there is a 25 per cent probability of 15 per cent non-recovery of network project spend incurred. Results are set out in Figure 11.

Figure 11: Projected outturn RORE for SONI in the network planning projects risk scenarios

RORE (%)	2015/16	2016/17	2017/18	2018/19	2019/20	Average
(A) Base case (75% probability)	7.6%	7.6%	7.6%	7.6%	7.6%	**7.6%**
(B) Base case (75% probability) adjusted for the PCG	2.2%	2.4%	3.5%	4.0%	3.8%	**2.2%**
(C) Network Planning risk (25% probability)	-2.0%	-4.2%	-1.0%	2.4%	1.5%	**-2.0%**
(D) Expected RORE adjusted for the PCG	1.1%	0.8%	2.4%	3.6%	3.2%	**1.1%**
(E) Shortfall in expected RORE adjusted for the PCG (= (A) – (D))	6.5%	6.8%	5.2%	4.0%	4.4%	**5.4%**

20.37 There is an implied RORE of 1.1 per cent against allowed returns of 7.6 per cent, i.e. there is a total expected shortfall of up to 540bps. In the Appellant's view an expected reduction in allowed returns at this scale would prevent the Appellant from securing the additional equity capital required to finance its business activities over the forthcoming control period and almost eliminates financial headroom to withstand downside shocks that might occur over and above the expected network project scenario considered in this analysis. It is recognised that, given the PCG capital is added to the equity base in full, that this is at the upper end of the potential range of outcomes but nonetheless, even if added on a probabilistic basis the gap would be significant.

(ii) Exposure to plausible downside shocks

20.38 The Appellant also asked KPMG to consider three scenarios which based on its experience (and, in the case of network planning, supported by a report prepared by Jacobs)[177] it considered plausible: network planning cost recovery risk; liquidity risk and revenue cap risk. In each case, the Appellant asked KPMG to assess whether it could reasonably be expected to manage these risk exposures, and by corollary whether it is financeable.

20.39 Network planning cost recovery risk: In the case of network project expenditure, Jacobs states:[178]

> *The preconstruction phase of project development is a crucial step in the project lifecycle and it is essential that SONI invest in this phase appropriately to minimise the risks and uncertainties for future stages of the project… Apportioning time and resources to identifying the right location, the right technology and to undertaking effective stakeholder management is a sound investment that minimises the risks and uncertainties that are*

177 Jacobs Report **[JM1/1]**.
178 Jacobs Report, section 7 **[JM1/1/18]**.

within SONI's control and produces a more robust project… These contingencies are large and reflect the very uncertain and investigative nature of the activity. They are much larger for example than those that would typically be provided for the construction activities on such projects…

20.40 Two scenarios were considered: first, that the Appellant's additional necessary expenditure is 10 per cent of the forecast set out in the Business Plan; and second, that it is 15 per cent of the forecast set out in its business plan. The results are presented below.

20.41 Figure 12 shows the projected outturn RORE for the Appellant in the network planning project risk scenarios:[179]

Figure 12: Projected outturn RORE for SONI in the network planning projects risk scenarios

RORE (%)	2015/16	2016/17	2017/18	2018/19	2019/20	Average
SONI business plan	7.6%	7.6%	7.6%	7.6%	7.6%	**7.6%**
Network Planning risk 1 (10%)	1.2%	-0.3%	1.9%	4.1%	3.6%	**2.1%**
Network Planning risk 2 (15%)	-2.0%	-4.2%	-1.0%	2.4%	1.5%	**-0.7%**

20.42 Both scenarios have a significant impact on the Appellant's RORE with negative RORE in a number of periods. The negative RORE implies that in some periods the Appellant will not be able to service its debt obligations. Under a RORE analysis, KPMG concludes that the Appellant's exposure to network planning costs is inconsistent with equity financeability and the reasonable downside exposure that will be assumed by equity investors. In respect of network planning risk exposure, KPMG concludes as follows:[180]

These results collectively suggest that SONI's exposure to Network Planning costs is inconsistent with equity financeability and reasonable downside exposure that might be acceptable to equity investors. It is also inconsistent with the implicit or explicit assumptions typically made by UK economic regulators with respect to the risk tolerance of even asset-heavy regulated utilities with considerably greater financial headroom. This, in turn, suggests that the FD exposes SONI to an excessive level of risk and implies a financeability problem.

20.43 Network planning is only one of the risks faced by the Appellant as outlined in AS1. As Aidan Skelly explains in AS1, the overall equity returns are highly sensitive to risks; not only network

179 KPMG3, paragraph 5.8.8 **[MC2/1/33]**

180 KPMG3, paragraph 1.33 [**MC2/1/5]**

planning project risks but also liquidity risks and revenue cap risks. Further analysis can be found in KPMG3.

20.44 Based on the risk scenarios provided by the Appellant, KPMG finds that:[181]

> *…the FD is likely to expose SONI to a level of risk that SONI will not be able to manage without additional financial support. This implies low or negative returns and profitability significantly below the relevant benchmarks, which any equity investors would be unlikely to accept when investing in SONI.*

(c) Failure to consider financial resilience

20.45 A critical component of the Utility Regulator's financeability assessment given the Appellant's circumstances, ought to have been to consider whether sufficient headroom existed within the Business Plan to accommodate reasonable downside shocks, without jeopardising the Appellant's ability to finance its activities.

20.46 For unexplained reasons, the Utility Regulator does not appear to have conducted a thorough analysis of the Appellant's financial resilience. There is no assessment of financial headroom in the Final Determination. Nor has the Utility Regulator published any downside scenario analysis for the Appellant. This is despite the fact that, as the Utility Regulator itself acknowledges, the Appellant will incur significant costs over the Price Control for activities such as Network Planning for which there is currently no revenue recovery mechanism identified in the TSO Licence. Indeed, the proportion of uncertain costs has increased significantly for the Price Control, as explained further in Ground 2.

20.47 The Utility Regulator's failure to conduct cross-checks to ensure the regulated company's financial resilience is contrary to best practice, citing in support Ofgem's approach to considering financial resilience of distribution network operators in RIIO-ED1 against plausible downside scenarios as a means to cross-check its Final Determination. Ofgem reported that the exercise:[182]

> *…enhanced our financeability analysis by taking more explicit account of actual embedded debt issues, ensuring our assessments are robust to a wide range of future interest rate scenarios and analysing more directly the resilience of DNO's capital structures to plausible downside scenarios.*

20.48 Based on the scenarios provided to it by the Appellant, KPMG concludes from its assessment of headroom and downside risks that:[183]

> *While SONI appears to have a sufficient liquidity to withstand such downside shocks in cash terms in the majority of cases, the shocks are likely to pose a significant financeability challenge for SONI from both debt and equity perspectives due to the large*

[181] KPMG3, paragraph 1.4 **[MC2/1/1]**

[182] See Ofgem, RIIO-ED1, Draft Determinations for the slow-track electricity distribution companies – Financial Issues, 30 July 2014, paragraph 3.24 and Ofgem, RIIO-ED1: Final Determination for the slow-track electricity distribution companies – Overview, 28 November 2014, paragraphs 5.38-5.40.

[183] KPMG1, section 8.6.5 **[MC1/1/102]**

financing requirement, the need to have strong confidence in the recovery of financial performance over time, and low equity profitability implying low financial headroom. This means that the scenarios tested are likely to affect its ability to raise financing in the first place.

20.49 The Utility Regulator's failure to thoroughly consider the Appellant's financial resilience provides further evidence that its conclusion that the Appellant is financeable is unsupported and lacks a robust evidence base.

21 Summary of relief sought

21.1 The errors described in the preceding sections clearly and unequivocally demonstrate that the Decision fails to secure the Appellant's financeability. The Appellant requests that the CMA remedy the defects in the Utility Regulator's Decision so as to ensure the Price Control secures its financeability.

21.2 In particular, the Appellant requests that the CMA introduce a margin-based approach to the remuneration of the Appellant and its investors in order to secure its financeability. KPMG1 assesses the appropriate level at which the margin should be set to secure the Appellant's financeability.

21.3 In summary, the Appellant requests that the CMA amend the Licence so as to provide for the recovery of a margin of 11 per cent on controllable costs. Proposed text for this licence modification is provided in Part V of this Notice. KPMG2 provides further details about designing and implementing a margin-based approach.

PART IV – GROUND 2

The Revenue Uncertainty Ground

22 Overview

22.1 Ground 2 concerns the errors made by the Utility Regulator in its approach to managing uncertainty for the Price Control Period (referred to as the **Revenue Uncertainty Ground**, as defined in section 4.3(b) above). In failing to appropriately manage uncertain costs in the Price Control, the Utility Regulator has created unprecedented levels of uncertainty for the Appellant, directly affecting its financeability.

22.2 In summary, there are a number of matters, notably PCNPs and additional IS capex outputs, which have effectively been omitted and in relation to which there is no clarity whatsoever. In respect of others, for example Dt, there is some sort of framework but one which is deficient in a number of respects whether through the cumbersome two-stage approval process or an absence of appeal rights. In other areas, such as DIWE and Qt, the regulatory framework which should be designed to reduce uncertainty in fact increases it and SONI has limited guidance on how the Utility Regulator might employ these terms.

22.3 In the Business Plan, the Appellant estimated that it required £132 million so as to efficiently finance its functions. The Utility Regulator provided £69 million by way of committed funding.[184] [185] It also identified that a further £28 million was likely to be required in respect of Network Planning, subject to intra-periodic review and scrutiny. The Appellant currently estimates that the costs will be in the region of £15-20 million. The Utility Regulator determined that the costs associated with Network Planning should be subject to a process whereby the Appellant seeks funding on a project-by-project basis, with no guarantee that the Appellant will recover its costs in each case. There is no express provision for this, save for the unusual situation where a project does not proceed, where the Dt mechanism provides for machinery for reimbursement. Even this figure will not be final: it will be subject to an *ex post* review and separately it will be subject to the possible application of the DIWE term. So the Appellant faces uncertainty as to whether its costs will be reimbursed in full, has no knowledge of the procedure which will be applied, and is in the dark as to which principles will be applied both as to the assessment of pre-construction expenditure and as to the application of the DIWE term.

22.4 Network Planning costs are not the only uncertain costs. For other Significant Projects (namely I-SEM where the costs are estimated to be £11.4 million[186] and DS3 System Services, where the costs are estimated to be £1.9 million), no specific provision is made even though the Appellant is expected to deliver these projects. This means that the Appellant is obliged to expend money subject to an *ex post* review by application of the DIWE term, applying unknown principles after the event. Moreover, the Appellant estimates that it is likely to incur a further £5-7.5 million in other Dt costs over the Price Control. The total “uncertain” revenues amount to

184 It should be noted that these two figures (£132 million and £69 million) include different elements making it difficult to compare like for like.

185 £67.3 million adjusted for real price effects.

186 Include the Appellant’s share of the total costs only.

approximately £37 million, over three-quarters of which relates to the Utility Regulator's *"key outputs"* of the Price Control.

22.5 In the Appellant's view, the complex machinery adopted by the Utility Regulator, which represents the exercise of a discretionary power not subject to appeal to the CMA, introduces an unnecessary element of uncertainty as to the recovery of costs which the Appellant is obliged to incur, thus rendering it difficult for the Appellant to raise funds either at all or on reasonable terms, in breach of the Utility Regulator's Financeability Duty.

22.6 The Appellant requests that the CMA read by way of introduction to this topic:

(a) AS1, which explains the impact of the Utility Regulator's errors in relation to uncertainty on the Appellant's financeability;

(b) BT1, which explains the uncertainties the Appellant faces during the Price Control Period and why these are exacerbated by the Decision; and

(c) "Evaluation of Uncertainty Mechanisms – SONI", a report by Cambridge Economic Policy Associates Ltd (the **CEPA Report**), exhibited to IA1, which provides expert comments on best regulatory practice in the management of uncertainty by sector regulators in the UK.

22.7 In respect of this ground of appeal, the Utility Regulator's Decision includes seven errors as summarised below.

Error 2: No cost recovery mechanism for PCNPs

22.8 The Appellant currently estimates that the costs of delivering PCNPs will amount to £15 - 20 million over the course of the Price Control.[187] There is currently no codified mechanism enabling it to recover these costs in the Licence (save for projects which are abandoned – which is expected to be the exception rather than the rule) and it is not clear as between the Final Determination and the Decision Paper what is intended by the Utility Regulator.

Error 3: No cost recovery mechanism for additional IS capex requirements

22.9 A considerable element of the Appellant's costs (£8.927 million in the Business Plan) relate to IS capex[188]. To the extent any unforeseen requirements for IS capex outputs arise, the Utility Regulator has determined that the Appellant should be exposed to 100 per cent of these costs.

Error 4: No suitable mechanism for recovering Significant Project costs

22.10 The Utility Regulator decided to expand the scope of the Dt mechanism for this Price Control so as to not only apply to unforeseen costs (as previously) but also to apply to the costs of certain Significant Projects, namely I-SEM, DS3 System Services[189] and any abandoned PCNPs.

187 This is the Appellant's current estimate of the figure previously estimated as £28 million in the Appellant's submission.

188 See Error 11 for further details.

189 Estimates for the implementation costs of I-SEM and DS3 System Services were not included in the Business Plan.

Error 5: No suitable right of appeal to the CMA

22.11 Decisions by the Utility Regulator on whether to award or deny the revenues claimed in respect of Significant Projects do not require a licence modification, which would give rise to a right of appeal to the CMA.

Error 6: Unworkable two-stage process

22.12 The Utility Regulator has introduced a two-stage process into the existing Dt mechanism whereby the Appellant must submit Dt claims for pre-approval up to a cap and must later report the actual costs which are then subject to an adjustment mechanism. The result is unworkable. The Dt mechanism was designed to facilitate recovery of unforeseen costs. Its expansion to embrace costs which are foreseen but not approved is likely to result in delay and extra cost, and creates downside-only risk for the Appellant, the extent of which cannot be quantified in advance. The Utility Regulator has confirmed that this process will also apply to PCNPs.

Error 7: DIWE

22.13 The Utility Regulator has introduced a mechanism allowing it to disallow recovery of costs from the Appellant where it deems the expenditure was inefficient or wasteful, without providing any guidance on its application.

Error 8: Qt adjustment

22.14 The Utility Regulator has introduced a “Qt” adjustment, which is unnecessarily broad in scope, and set out its intent to claw-back any “over-payment” on tariffs on a retrospective basis to 1 October 2015 without engaging in any consultation. The Decision promises guidance as to how this is to operate, but this has not been forthcoming, and its absence, as well as the general suggestion that the Utility Regulator can apply its decisions retrospectively, adds to the uncertainty.

22.15 The inadequacy of the Decision in relation to uncertainty is exacerbated by the Utility Regulator’s failure to include any detailed, coherent or consistent explanation in the consultation documents or in the Final Determination concerning its approach to managing uncertainty and its reasoning, and its failure to consider and/or adopt alternative approaches.

22.16 The consequence of the Utility Regulator’s errors is that a significant proportion of the Appellant’s revenues for the Price Control remain unaccounted for and is therefore at risk. In previous price controls, it was not unusual for approximately 10 per cent of the Appellant’s required revenues to be subject to some degree of “uncertainty” and therefore not capable of ex ante allocation. The Utility Regulator’s Decision leaves approximately £31.4 million of identified estimates unaccounted for at the outset, leaving aside any unforeseen funding requirements, which the Appellant anticipates to be in the region of £5-7.5 million based on previous experience, making a cumulative total of approximately £37 million. This is a considerable sum in the context of an overall price control settlement of £69 million (equivalent to some 35 per cent of the allowed revenues) and the lack of visibility over recovery of such a significant portion of revenues makes it extremely difficult for the Appellant to raise finance to fulfil its licensed obligations being funded for only £6.6 million of capital and requiring £35-40 million. The Appellant acknowledges that it faces greater challenges and changes in the period up until 2020 as compared with previous price controls. But this only points to the Utility Regulator having to do more to manage uncertainty to secure its financeability, not less. The Utility Regulator’s failure to tailor its approach to uncertainty so as to minimise the financial risks to the Appellant has a material adverse impact on the Appellant's financeability in breach of the Financeability Duty.

22.17 Accordingly the Utility Regulator's Decision in relation to managing uncertainty was wrong by reference to the statutory grounds detailed in Part II of the Notice, as summarised below:

(a) the Utility Regulator failed under Article 14D(4)(a) of the Electricity Order to properly have regard to its duties under Article 12(2)(b) of the Energy Order to have regard to the need to secure that licence holders are able to finance their regulated activities;

(b) The Utility Regulator failed under Article 14D(4)(a) to properly have regard to its duties under Article 12(5)(a) of the Energy Order to promote the efficient use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity;

(c) The Utility Regulator failed under Article 14(D)(4)(d) in that the modifications fail to achieve, in whole or in part, the effect stated by the Authority by virtue of Article 14(8)(b) as regards the Utility Regulator's failure to secure the Appellant's financeability and, specifically, as regards the Utility Regulator's introduction of a two-stage approval process for recovering uncertain costs;

(d) The Utility Regulator was in repeated breach of its obligations relating to best regulatory practice in failing to adopt a suitable approach to managing uncertainty.

22.18 The impact of the Utility Regulator's errors through failing to manage revenue uncertainty is set out below, and is further summarised in Sections 15 and 16 of Part IV of the Notice and discussed in AS1, FS1, RJM1 and BT1.

22.19 The Appellant requests the relief summarised below and set out in Part V of the Notice.

23 The uncertainty that the Appellant faces during the Price Control Period

23.1 Importantly, the Appellant is exposed to meeting the costs of delivering outputs including Significant Projects during the Price Control Period, for which it is currently unremunerated. In addition, there are a number of uncertain but less significant cost items which are outside the Appellant's control and which will inevitable fall due within the Price Control Period. These include costs which can be pre-identified as being suitable to be treated on a pass-through basis, such as pension deficit repairs and mandatory fees including ENTSO-E membership, inter TSO compensations, and regional security coordination costs.

23.2 The Appellant is of course used to dealing with expenditures that entail some uncertainty. Often the nature of the uncertainty it faces can be categorised as follows:[190]

(a) cost uncertainty – relating to the size of the expenditure required to deliver a given set of outputs;

190 CEPA Report, paragraph 2.1 **[IA1/1/14]**.

(b) timing uncertainty – relating to when, if ever, the expenditure would need to take place (and whether or not this will arise during the relevant price control period); and/or

(c) output uncertainty – relating to the need for and the quantity or quality of outputs that the regulated company is required to deliver.

23.3 The Appellant instructed CEPA to provide an assessment of the Utility Regulator's Decision and to consider the role of uncertainty mechanisms and the characteristics of uncertainty mechanisms used in UK best practice regulation. CEPA explains that the uncertainties which individual companies face are always specific to the business in question and that as a result:[191]

> *…good regulatory practice is for regulators to undertake a detailed assessment of the types of uncertainty that will be faced and the appropriate proportionate response to each type.*

23.4 CEPA also explains that the degree of uncertainty of expenditures that need to be undertaken by regulated companies in some cases becomes materially higher than usual and explains that these merit particular treatment:[192]

> *Where these uncertainties are material enough, they could expose customers to significant forecasting uncertainty, or the regulated company to an increase in the cost of capital and financeability risk. Therefore, many UK regulators introduce uncertainty mechanisms as part of the ex-ante regulatory framework, as a means of alleviating these issues.*

23.5 The Appellant submits that Significant Projects merit particular treatment due to their scale and complexity and to the level of costs involved. The Appellant uses the term Significant Projects to refer to projects where the cost is forecast to amount to over £1 million. The Appellant considers this to be a reasonable threshold in the context of allowed opex revenues of approximately £11 million per annum and allowed capex of £6.6 million over the Price Control Period. It is also at the top end of SONI's equity returns of between £0.4 million per annum (codified arrangements) to approximately £1 million per annum (expected return) and represents approximately 15 per cent of the average RAB (codified) or approximately 6 per cent (expected) RAB. Details of the main Significant Projects are discussed in detail in RJM1. Briefly, they include:

(a) the implementation of the Integrated Single Electricity Market (**I-SEM**) – costs are expected to amount to approximately £11.4 million across the Price Control Period;

(b) the implementation of the DS3 System Services programme – costs are expected to amount to approximately £1.9 million for DS3 System Services across the Price Control Period; and

(c) the delivery of Network Planning, involving the delivery of large-scale PCNPs – costs are expected to amount to approximately £15 - 20 million across the Price Control Period.

191 CEPA Report **[I1/1/3]**.

192 CEPA Report, Executive Summary **[IA1/1/2]**.

23.6 The impact of having to fund the implementation of I-SEM and DS3 System Services alone (with a combined forecast cost at least equal to the RAB) over a relatively short time-frame of two to three years would in itself be challenging in terms of cash flow. This is not typical for the Appellant given that it has a limited asset base, but it is required to deliver large operations related projects from time to time. However, for this Price Control, the Appellant is also required to fund the pre-construction activities of developing the transmission system. In addition, the Appellant will be required to manage industry payments following the implementation of the I-SEM and DS3 System Services projects, which will be both larger and more difficult to forecast.[193]

23.7 The Utility Regulator has left the costs for various items of expenditure, including the Significant Projects listed above, to be recovered outside of the ex-ante regulatory allowances. It is recognised that if certain costs are genuinely unknowable, or if there is a significant change of circumstances warranting a reopener of any regulatory settlement, a machinery must be put in place, subject to appeal to the CMA (as if the reopener were included in the initial Decision)[194]. By contrast, the Utility Regulator offered little or no base assessment of costs but only a complicated machinery, ultimately, of *ex post* review after the application of an assessment of the efficiency of the expenditure. So, instead of offering "incentive" regulation to beat a minimum cost and thus revenue target, what is on offer is "disincentive" regulation, with no minimum revenues, so adding to unique regulatory risks.

23.8 The Utility Regulator has also created additional unwarranted uncertainty by failing to specify how it will apply new mechanisms, such as DIWE and the Qt term, which enable it to make additional revenue adjustments during the Price Control. The lack of visibility of the revenue streams required to finance the Appellant's functions detracts investors and heightens the Appellant's risks, as explained in Ground 1 , the Financeability Methodology Ground. In BT1, Bill Thompson explains that in his view, the Price Control:[195]

> *…contains a set of arrangements which create significant uncertainty for its operations, resulting in new risks. This creates significant uncertainty for SONI, not least because it is operating in an increased risk environment due to the ongoing evolution of regulatory arrangements aligned to achieving public policy objectives. As a result, the overall revenue framework does not lend itself to providing SONI with the necessary revenue streams on a timely and appropriate basis to carry out the wide range of activities it is expected to carry out on behalf of consumers. It lacks the basic incentive properties and recourse mechanisms expected of a good regulatory framework and as such it risks the delivery of consumer benefits – and arguably acts against it.*

23.9 Overall, the Utility Regulator's Decision increases the degree of risk faced by the Appellant in terms of its ability to finance its regulated activities. As CEPA reports: [196]

193 This is because the Appellant will be responsible for (a) ensuring generation capacity payments, which under I-SEM will result from a competitive process, and (b) increased System Services payments to generators as a result of changed operations resulting from DS3 System Services.

194 CEPA Report, Executive Summary **[IPA1/1/4]**.

195 BT1, paragraph 299.

196 CEPA Report, Executive Summary **[IPA1/1/8]**.

[The Decision] raises a number of financeability issues for SONI which in turn will increase its financing costs and result in higher prices for customers or reduce the outputs. This runs counter to the main objective of introducing uncertainty mechanisms.

24 Error 2: Failure to provide a cost recovery mechanism for PCNPs

24.1 The Appellant acquired responsibility for Network Planning activities on 1 May 2014 when the function was formally transferred to it from NIE. Network Planning is a generic term used to describe both the Project Identification (Phase 1) and Pre-Construction activities or PCNPs (Phase 2) of the Transmission Project Life Cycle. Since May 2014, the Appellant is responsible for both these phases prior to Project Construction (Phase 3).

24.2 As explained in Part I of this Notice and in Part C of BT1, the Utility Regulator required the Appellant to take responsibility for Network Planning consistent with the requirements of the European Commission's Article 9(9) Certification Decision in 2013 and provided assurances prior to the transfer that the Appellant would be entitled to recover its costs. As part of this transfer, there were considerable communications between the Appellant and the Utility Regulator. The TIA between NIE and the Appellant was formally modified and approved by the Utility Regulator on 27 March 2014 to reflect the transfer of the function.

24.3 Advancing PCNPs from conception to construction now forms a significant part of the Appellant's regulated activities. Indeed, the commissioning of the North-South Interconnector – a Significant Project - was identified by the Utility Regulator as a "*key output*" of the Price Control Period.[197] The Appellant estimates that the cost of delivering PCNPs over the Price Control is approximately £15-20 million. This is less than the £28 million in its Business Plan which the Appellant set out would be recoverable under the TIA arrangements, but, as explained in BT1, the reason for difference in estimates over time is that both the project pipeline and the projects themselves are assessed, re-assessed and updated on an ongoing basis, often adjusting significantly and mainly due to external factors such as planning applications. Further discussion of pre-construction risk assessment can be found in the Jacobs Report.

<u>The Utility Regulator's Decision</u>

24.4 In the Licence, the Utility Regulator included *"costs associated with Transmission Network Pre-construction Projects"*[198] in its list of pre-defined categories of costs in respect of which any claims made will be processed under the Dt process and carried through into the SSS tariff. As explained in BT1, this is contrary to the TIA arrangements and means that the wrong customers pay. In the Final Determination, the Utility Regulator explained that only costs associated with PCNPs which are <u>not</u> transferred onto the construction phase (because the project is not deemed to be viable to continue) can be recovered using this process.[199] This leaves open the question as to how the costs of PCNPs that are transferred onto the construction phase are to be recovered. The Utility Regulator suggests that the Appellant's costs of PCNPs will be recoverable through the Transmission Interface Arrangements but there is no procedure set

197 Final Determination, Executive Summary, page 3 **[NOA1/12]**.

198 Final Determination, paragraph 439 **[NOA1/12]**.

199 Final Determination, paragraph 483A **[NOA1/12]**. The Appellant does not anticipate any projects being abandoned so this provision is of limited use.

down in the TIA for the Appellant to recover its costs.[200] Even the Utility Regulator states in both the Final Determination and the Decision that it will continue to work with the Appellant to develop the process.[201] The TIA simply states that any amounts payable from NIE to the Appellant:[202]

> *shall be in accordance with the respective price control arrangements for NIE and SONI or such other regulatory arrangements as SONI has agreed with the Authority are applicable…*

24.5 In fact, in November 2014, the Utility Regulator wrote to the Appellant and NIE specifically prohibiting the parties from exchanging money in relation to network planning costs.[203]

24.6 The Utility Regulator stated in the Final Determination – and continues to maintain - that it will *"continue to work with SONI and NIE networks in developing the pre-construction / construction project provisions"*.[204] Yet still the process of recovering revenues is not clear. The Appellant SONI sought to engage with the Utility Regulator in relation to the framework of recovery for PCNPs on a number of occasions. However as outlined in Section C of BT witness statement much time was spent discussing the treatment of recovery in terms of opex or capex rather than more fundamental issues concerning the operation of the recovery process and how this would enable the fulfilment by the Appellant of its functions.

24.7 In its engagement with the Utility Regulator, the Appellant emphasised that on completion of the PCNP, there are four possible scenarios all of which need to be addressed in cost recovery mechanisms in the TSO Licence:[205]

(a) the PCNP does not proceed to construction;

(b) the PCNP proceeds to construction by NIE;

(c) the PCNP proceeds to construction by another entity; and

(d) the PCNP proceeds to construction by the Appellant, where it has exercised its step-in rights in accordance with provisions in the TIA.

24.8 In the Decision Paper, the Utility Regulator provided no further assurance that all such costs would be recoverable, simply stating: [206]

> *As stated in the Final Determination costs associated with [PCNPs] being planned by SONI, will also accumulate on a separate RAB until such time as the project receives the Utility Regulator's approval to transfer the project to NIE for development…Each of these*

[200] In the Final Determination, paragraph 483B, the Utility Regulator states *"these costs will be reviewed, approved by the Utility Regulator and will be placed on the TUoS tariff, through the Transmission Interface Arrangements (TIA) framework"* **[NOA1/12]**. Separately, and in direct contradiction with this statement, the Utility Regulator has written to each of SONI and NIE prohibiting the recovery of charges under the TIA framework until further notified.

[201] See for example, paragraph 492 of the Final Determination **[NOA1/12]** and paragraph 97 of the Decision Paper [**NOA1/18**].

[202] TIA, Section N, paragraph 3.2 **[NOA1/4]**

[203] See paragraph 192 of BT1.

[204] Final Determination, paragraph 485 **[NOA1/12]**.

[205] See exhibit **[BT1/62]** to BT1 for further details

[206] Decision Paper, paragraph 93 **[NOA1/18]**.

projects will be subject to case-by-case approval before costs associated with the project can be accumulated on a separate RAB. Only amounts approved by the UR will … be… transferred between SONI and NIE Networks.

24.9 To date, there is no provision in the Licence for the Appellant that codifies the recovery of the costs of any PCNPs that are transferred to NIE for construction. Nor is there any provision for the Appellant to recover the costs of PCNPs that are transferred to another non-NIE entity or in circumstances where the Appellant might invoke its "step-in" rights. The former is necessary pursuant to the Competition Commission's direction in the NIE Determination[207] while the latter is a legal requirement arising from paragraph 60 of the Certification Decision and is provided for in Section O of the TIA but to date has not been met. In its Decision Paper the Utility Regulator suggested that these were matters which could be addressed in the course of time as part of some unspecified future consultation.[208] Yet, as explained in Part D of BT1, the absence of any cohesive codified process being put in place has created further unnecessary uncertainty for the Appellant. It has been three years since the Appellant took over responsibility for Network Planning from NIE and there is no justification for the persistent delay. Moreover, for step-in rights to be meaningful[209] then revenue provisions must be available. If these rights are not meaningful this would be likely to call into question the Appellant's certification as TSO.

<u>Why the Utility Regulator's Decision is wrong</u>

24.10 It is unacceptable that the Utility Regulator should fail to provide a mechanism for the Appellant to recover the estimated £15-20 million of costs associated with delivering PCNPs. The Appellant has no visibility as to how it is supposed to recover these costs and is required to carry out work on PCNPs and incur significant costs in circumstances where the recoverability of such costs and the applicable mechanism remains uncertain. This is contrary to best regulatory practice which is to provide certainty for regulated companies and for consumers who benefit through the efficient development of the transmission system.

24.11 Clearly it is not in the interests of consumers for the Appellant to suspend work on PCNPs so the Appellant has progressed work, albeit with trepidation given the lack of certainty as to how the costs it has incurred since taking on the function and across the Price Control Period will be recovered. PCNPs need to be progressed now if the transmission network is to develop to meet the needs of the electricity industry in Northern Ireland in line with the Utility Regulator approved "Transmission System Security and Planning Standards". However, the continuing uncertainty surrounding delivery of these projects could hamper this work given its negative effect on cost recovery assurance and the lack of visibility concerning the financeability of the business. In addition, it cannot be good practice to apply a mix of *ex ante* and *ex post* regulation, particularly when there is no certainty in relation to how the *ex post* arrangements would apply. Notably, as explained in AS1, leading banks have stated that they would require a "Letter of Comfort" from

[207] NIE Determination, paragraph 5.272 states *"[w]e expect the UR to consider the potential for projects to be developed and subsequently owned and maintained by a party other than NIE (e.g. a party appointed by SONI or the UR through a competitive process). Whilst there would be administrative costs and practical difficulties to overcome in the establishment of more competitive arrangements in Northern Ireland, there are also potential benefits to be realised from competition"*.

[208] Decision Paper, paragraph 95 **[NOA1/18]**.

[209] The European Commission has commented on the importance of effective step-in rights in the context of the certification of EirGrid as TSO in Ireland – further discussion in the recitals to Commission Decision C(2013) 2169, Eirgrid/ESB, 12 April 2013 (available at https://ec.europa.eu/energy/sites/ener/files/documents/2013_060_ie_en.pdf).

the Utility Regulator relating to the Appellant's ability to recover its costs through the tariff system not least because of the lack of certainty concerning the regulation of Network Planning.

24.12 It appears that one of the reasons why the Utility Regulator has not yet reached a decision on cost recovery is because of uncertainties surrounding its proposed process for assessing PCNP costs, as explained in BT1. The Utility Regulator has confirmed its intention to approve the costs of each project on both an *ex ante* and *ex post* basis, by first imposing an *ex ante* allowance cap and then subsequently reviewing the submission with a view to permitting the recovery of only actual costs which are efficiently incurred. The Appellant strongly objected to this approach being applied in relation to PCNPs because:

(a) the two-stage approach gives rise to a real risk of delay, hindering project efficiency and impedes the Appellant's ability to fulfil its obligations under the TSO Licence;

(b) the Appellant is exposed to asymmetric risk in respect of the costs of PCNPs (i.e. the Appellant cannot benefit from any efficiency savings made but is exposed to loss in a downside scenario) and this risk is potentially exacerbated by the two stage approach given the difficulties the Utility Regulator will no doubt face in setting an *ex ante* cap; [210] and

(c) the Utility Regulator has no vires in statute, the TSO Licence or any other legal basis to introduce an *ex ante* approval. As explained in paragraph 192 of BT1[211], the Appellant received a legal opinion from Leading Counsel confirming the lack of legal vires held by the Utility Regulator and wrote to the Utility Regulator informing them of the same, seeking clarification, which has not yet been provided.

24.13 The Utility Regulator eventually attempted to codify the two-stage process in its Decision by redefining "Transmission Network Pre-construction Project" in the Licence as meaning a project:

> *(a) which is –*
>
> *(i) identified (either by the Licensee or by the Transmission Owner) as necessary to undertake in respect of the development of the transmission system;*
>
> *(ii) submitted by the Licensee to the Authority for approval; and*
>
> *(iii) approved by the Authority as necessary to undertake in respect of the development of the transmission system; and*
>
> *(b) for which the Licensee is responsible for undertaking the activities that are required to progress the project from the conceptual stage to (but not including) its construction.*

24.14 The Appellant considers this insufficient as a basis for imposing a two-stage process – and, in any event, fails to see why the steps envisaged a stages (a)(ii)-(iii) cannot be undertaken contemporaneously and therefore where the requirement for "pre-approval" arises.

[210] See in particular the Appellant's response to the Utility Regulator's licence modification consultation, dated 23 March 2016, and its further response, dated 14 June 2016 (exhibited to RJM1 as, respectively, **[RJM1/2]** and **[RJM1/4]**); and the Appellant's letter to the Utility Regulator dated 15 April 2016 **[BT1/56]**

[211] See the Appellant's letter to the Utility Regulator dated 11 July 2016, at exhibit **[BT1/62]**.

24.15 More importantly the Utility Regulator decision to impose a cap (*ex ante*) on the amount recoverable for each individual PCNP[212] results in an asymmetric risk profile where the Appellant must itself fund any costs incurred in excess of the cap. This significantly impacts its financeability and there is no evidence of the Utility Regulator undertaking any analysis of the impact of its decision.[213] Moreover, as explained in BT1, the concept of a cap delivers precisely the wrong incentive for pre-construction activities, which should be invested in so as to minimise whole of life costs.

24.16 In the Decision, the Utility Regulator confirmed that the existence of a cap did not mean that the Appellant could not recover costs in excess of the cap stating:[214]

> *We have reiterated to SONI that it has the ability to submit additional Dt claim(s) if unexpected costs develop beyond the upper cap, As with any other claim under the Dt provisions, if such claims were to be submitted then the UR would assess it to determine if it is in the consumer interest and make a decision on whether or not to approve it accordingly.*

24.17 This approach suffers from the same defect as the existing proposals in relation to Network Planning in that is uncertain and the process is unclear. The Utility Regulator has previously stated that only the costs of PCNPs that do not proceed to construction can be recoverable under Dt. It cannot now intend that the Appellant should seek recovery of costs incurred for PCNPs that do proceed to construction in excess of any cap it imposes using Dt, while costs incurred up to the cap are recoverable direct from NIE. This is yet another example of the Utility Regulator's inappropriate use of the Dt mechanism.

24.18 As CEPA explains, on the face of this statement, this suggests that the Appellant may need to utilise two different mechanisms to recover the costs of the same project, which is unworkable and unnecessarily burdensome:[215]

> *This would imply that for pre-construction projects that proceed to construction, and unexpected costs developed beyond the determined cap by the UR, SONI may need to seek recovery of its costs from two routes:*
>
> - *the upfront cost allowance for the project through the TIA framework mechanism (i.e. invoiced by SONI to NIE); and*
> - *the additional cost claim (to the extent it is agreed by the UR) through the Dt mechanism.*

24.19 In practice, the Appellant's ability to forecast pre-construction costs is hampered by the fact that these costs are not within the Appellant's control. Introducing a "pre-approval" process potentially results in perverse investment incentives, as explained in BT1. As Jacobs reports in

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212 Final Determination, paragraph 489 **[NOA1/12]**.

213 Note that Opex costs (i.e. the day-to-day business costs associated with the network planning function) are subject to the 50/50 risk share mechanism – see the Final Determination, paragraphs 487-488 **[NOA1/12]**.

214 Decision Paper, paragraph 92 **[NOA1/18]**.

215 CEPA, paragraph 4.3 **[IA1/1/37]**.

sections 2–7 **[JAC1/01/Pages 3–20]**, pre-construction works are generally accepted to be the elements of the cost most vulnerable to cost forecast deviations and increases. This is due to the technical and planning considerations or issues which arise at this stage which means that alternative plans and actions must be undertaken.[216]

24.20 The Utility Regulator has therefore failed to provide adequate justification for requiring pre-approval before the commencement of works. Given that the Appellant will only be allowed its efficient costs in the *ex post* assessment it is clear that this degree of interference by the Utility Regulator does not offer any additional consumer benefits to those already available, is contrary to its duty to promote efficiency and has the potential to frustrate the Appellant in delivering its activities.

24.21 The Appellant's fundamental concern is that the Utility Regulator has failed to prescribe a suitable process which permits it to recover the significant costs that need to be incurred in order to deliver PCNPs and allow it to be able to permit potential funders to assess the Appellant's creditworthiness. In fact, this has been exacerbated by the Utility Regulator's letter of November 2014, which states that the Appellant is not permitted to pay NIE (and NIE is not permitted to pay the Appellant) directly in respect of costs associated with the Network Planning function under the TIA. The Appellant assumes that the purpose of this letter was because the Utility Regulator wanted to ensure a proper process was put in place under its Licence.

24.22 Given the substantial amounts of money involved - £15-20 million on current estimates - and the importance of transmission network development for Northern Ireland consumers, the Utility Regulator has erred by failing to reach a decision setting out how the Appellant will recover costs incurred, including by failing to include a modification in the Licence that confirms that such costs are recoverable, as required by lenders, in breach of its Financeability Duty and failing to set forth a suitable process for the submission and assessment as to whether such costs have been efficiently incurred, contrary to the interests of consumers.

25 Error 3: Failure to provide a cost recovery mechanism for additional IS capital investment

25.1 As explained in BT1, information systems play a critical role in enabling the Appellant to efficiently operate the Northern Ireland electricity transmission system. Given the broad range of challenges and changes faced by the Appellant between now and 2020 it is likely that additional demands may be placed on the Appellant to invest in information systems. The Utility Regulator has failed to provide a mechanism in the Final Licence Modifications for recovery of efficiently incurred costs associated with the delivery of any additional IS Capex projects over and above those identified in the Final Determination.

<u>The Utility Regulator's Decision</u>

25.2 The Utility Regulator recognised that the Appellant was likely to need to provide additional investment in IS Capex over and above that set out in the Business Plan and identified in the Final Determination.[217]

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216 The Appellant understands Ofgem treats pre construction costs for National Grid UK on an upfront ex ante basis.

217 Final Determination, paragraph 245 **[NOA1/12]**.

25.3 In its Decision, the Utility Regulator set out a "high level overview" of outputs and "a more extensive list" (see Appendix A of the Final Determination), both of which are based on the key areas of the Appellant's original submission.[218] The Utility Regulator confirmed that these outputs are not fixed:[219]

> *These outputs are not fixed and the Utility Regulator expects SONI to use its discretion to allocate allowances in an efficient manner. However, it does provide a general forecast for the type and level of output consumers can expect from the price control.*

25.4 It also recognised that additional capex requirements may arise during the course of the Price Control:[220]

> *Because of [SONI's] risk averse approach to forecasting capex the Utility Regulator considers the allowances to have sufficient flexibility to facilitate SONI prioritising and managing this capex allowance <u>should other capex requirements arise</u> in order for SONI to meet all its obligations in operating a safe, secure and reliable power system.*

25.5 The Utility Regulator refused to provide any mechanism for recovering such costs on the basis that it considered the allowances made to be sufficient. The Utility Regulator explained that it:[221]

> *…views the allowances provided under IT OPEX and IT CAPEX to be sufficient and appropriate to enable any such system changes to be captured and therefore do[es] not expect to receive or to provide approval for system change submissions via the Dt mechanism.*

25.6 It is therefore currently unclear how costs incurred in respect of these additional requirements can be recovered. The Utility Regulator seems to anticipate that the approved allowance will have to cover the costs of additional and unforeseen IS capex outputs. This is despite the fact that such allowance has been calculated only in respect of the outputs listed in the Decision and without making provision for unforeseen requirements. Given the dependency of the TSO business on information systems, this raises significant concern for the Appellant in terms of its ability to absorb any additional costs associated with these outputs.

25.7 This decision is unacceptable in circumstances where:

(a) the Utility Regulator already reduced the allowances sought in the Appellant's Business Plan for seven out of eight key IS capex projects by 10 per cent and, in relation to the eighth project, by 100 per cent;[222]

(b) the Appellant will be exposed to the costs of any spend over the allowance limit pursuant to the new 50/50 risk share mechanism (the impact of which is heightened due to the Appellant's relatively small portfolio of projects);[223] and

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[218] See Section 5.1.4 of the Decision Paper **[NOA1/19]**.

[219] Final Determination, paragraph 249 **[NOA1/12]**.

[220] Final Determination, paragraph 245 **[NOA1/12]** (emphasis added). The Appellant notes that did not consider its forecasts to be overly risk averse.

[221] Final Determination, paragraph 441 **[NOA1/12]**.

[222] These deductions must be viewed in addition to those set out in Error 11.

(c) the Utility Regulator has specifically stated that it does not expect to provide approval in respect of additional costs associated with system change submissions via the Dt mechanism.[224]

25.8 The Utility Regulator's Decision appears to have been motivated by a concern that the Appellant had sought to cover itself for all possible scenarios:[225]

> *As was stated in the Gemserv IT report, the SONI cost submission appeared to be well provided for. Many of the costs lines appear to be based on empirical information while others are provisional sums based on assumptions.*
>
> *In relation to the provisional sums the requirements are not adequately defined for an accurate estimate to be determined. For an ex ante allowance SONI appear to include contingency provisions based on worst case scenarios to ameliorate the risk of getting it wrong. In this regard SONI appear to have taken a risk adverse approach.*

25.9 However the Gemserv report qualified its statement which was not included in the Utility Regulator reference:[226]

> *The latter is not surprising as many of the requirements are presently not adequately defined for an accurate estimate to be determined. For an ex ante allowance it is not unreasonable to include contingency provisions based on worst case scenarios to ameliorate the risk of getting it wrong. In this case, SONI seems to have, <u>not unreasonably</u>, taken that risk adverse approach. (Emphasis added)*

25.10 The Gemserv Report recommended the application of a 10 per cent reduction to all allowable "key areas".[227] It is apparent from the Report that this was motivated by a view that the Appellant might benefit under the new risk sharing mechanism (as discussed in [Part II]) if no reduction was implemented:[228]

> *IT requirements are changing and system operators will require more sophisticated systems to control more demanding grids. This is fully reflected in the SONI submission that at £8,927k is about £5,500k more than similar allowances in the last price control period. <u>This large increase in forecast IT costs may not be a reasonable baseline for a 50:50 +/- gain share arrangement the UR is proposing [to] implement</u>. On the basis that the overall allowance will form the reference point for a gain share arrangement Gemserv would recommend the following changes… (Emphasis added)*

25.11 However, Gemserv made no recommendation to include additional output requirements on top of those set out in the Business Plan. The Appellant notes that Gemserv were not requested to make a recommendation for an allowance in the context of ensuring the financeability of the Appellant. Rather, Gemserv were engaged for the purpose of providing an initial view about

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223 Final Determination, paragraph 456 **[NOA1/12]**.

224 Final Determination, paragraph 441 **[NOA1/12]**.

225 Final Determination, paragraph 214 **[NOA1/12]**.

226 Gemserv Report, pages 19-20 **[NOA1/16]**.

227 Gemserv Report, page 19-20 **[NOA1/16]**.

228 Gemserv Report, page 19-20, section 5.9 **[NOA1/16]**.

what operational independence (from the EirGrid Group) would mean from an IS perspective, and assisting the Utility Regulator to consider the Appellant's Business Plan submission in that context.[229]

Why the Utility Regulator's Decision is wrong

25.12 The Appellant submits that it was unreasonable for the Utility Regulator to implement Gemserv's recommendation without considering the context in which that recommendation was provided, the justification Gemserv provided for proposing a reduction in allowances and in isolation of any consideration of unforeseen IS capex requirements. The Utility Regulator's approach lacks justification and is unreasonable. Clearly, it is appropriate to apply efficiency mechanisms to incentivise TSO operations in certain circumstances. However, the Appellant cannot be expected to deliver the outputs submitted in its Business Plan and to respond to new developments during the price control when it is also obliged to take responsibility for 50 per cent of any expenditure in excess of the allowance, in circumstances where the Utility Regulator has stated that it does not expect to approve additional IS capex submissions via the Dt mechanism (nor does it provide an alternative mechanism pursuant to which such costs can be recovered). This leaves the Appellant facing unnecessary financial risk in terms of non-recoverability of efficiently incurred costs arising from discharging its statutory and licence requirements.

25.13 The Utility Regulator has failed to demonstrate that it properly considered the impact of its Decision on the Appellant's financeability. There were other options available to the Utility Regulator in terms of the various elements and their packaging which could have been pursued, including maintaining an efficiency target to incentivise the Appellant whilst limiting the financial risk to the Appellant through the implementation of supporting arrangements to provide for further allowance for unforeseen requirements. There is no evidence that the Utility Regulator considered these options or whether these could lead to better outcomes for the Appellant and for consumers.

25.14 The degree of uncertainty in terms of expected outputs, the potential for additional projects to be required and the lack of a coherent cohesive process should this be the case heightens the risk environment for the Appellant which in turn impacts its financeability as explained in BT1 and Ground 1, the Financeability Methodology Ground.

26 Error 4: Failure to provide a suitable cost recovery mechanism for Significant Projects

26.1 The Dt mechanism existed in the Licence prior to the Price Control, albeit its use was restricted previously to "*unpredictable costs*".[230] These were expected to be non-controversial and, for example, included uncertainty concerning third party charges or decisions.

229 Gemserv Report, page 4 section 1.1 **[NOA1/16]**.

230 2010-2015 Decision Paper, page 6 **[NOA1/6]**.

The Utility Regulator's Decision

26.2 However, in the Decision the Utility Regulator has materially changed the application of Dt. It is the chosen means by which a significantly expanded category of costs, representing significant output requirements which are in principle predictable, is to be recovered.

26.3 This represents a change of policy on the part of the Utility Regulator. At the outset of the Price Control, it explained that it intended to limit the application of the Dt mechanism by specifying a pre-defined category of events within the Licence in relation to which the Dt mechanism could be employed. It explained its approach as being consistent with that adopted by the Competition Commission in relation to NIE noting:[231]

> *The CC removed the general reopener as they viewed it as giving the regulated company insufficient incentive to be efficient and so exposes consumers to the risk of excessive costs.*

26.4 The Utility Regulator did not offer any explanation as to why it considered it appropriate to adopt the same approach for the Appellant's business as the CC had for NIE despite the significant differences between the two business models. Further and in any event it failed to accurately represent the CC's findings in NIE that the use of the Dt mechanism within NIE's revenue control operated against the public interest, and its ultimate decision not to include a Dt term within the revised price control design.

26.5 The Appellant considers that its anticipated uncertain costs can be grouped into three categories:

(a) Reopeners

Costs which were foreseeable but which the Appellant could not quantify because the parameters were not sufficiently known or the estimates were wide-ranging – for example, the costs associated with delivering Significant Projects;

(b) Pass-through Ats

Costs which were foreseeable but which the Appellant could not quantify as they fell outside of its control – for example, the costs of pension deficit repair and other EU related mandated fees e.g. ENTSO-E membership, Inter TSO compensation, etc.; and

(c) Appropriate Dts

Costs which were genuinely unforeseeable – e.g. costs arising from a Change of Law (as defined in the Licence), compliance with various statutory requirements etc.

26.6 Had the Utility Regulator sought to categorise the various uncertain costs it would have realised that it was not appropriate to group them all together. The Utility Regulator provided no explanation as to why it considered the Dt mechanism to be the appropriate uncertainty mechanism to deal with each different category of cost described above. It simply listed the pre-

231 Final Determination, paragraph 429 **[NOA1/12]**.

defined categories without seeking to differentiate between them. The same mechanism and process therefore applies to recovery of a one-off lump sum of, say, £50,000 to cover a membership fee as it does to recovery of multiple claims concerning the cost of implementation of I-SEM and providing for DS3 (which are each expected to cost multiple millions).

Why the Utility Regulator's Decision is wrong

26.7 The Utility Regulator's approach of using a single mechanism to capture both unforeseen costs and certain Significant Projects constitutes a failure to exercise its responsibility to the Appellant – in line with good regulatory practice – to consider each category of uncertainty individually and provide for the most appropriate mechanism in each case.

26.8 Good regulatory practice is evident from the well-established approach taken by other UK sector regulators when designing uncertainty mechanisms, as identified in the CEPA report. This involves the regulator:

(a) balancing the benefits of using uncertainty mechanisms alongside the impact is has on overall financeability – this involves consideration of the benefits the mechanism can generate (with customers only paying for outputs they receive) with the potential costs (with customers taking on more of the risk);[232]

(b) tailoring the design of any uncertainty mechanism to the specific uncertainty faced by the regulated company – there is no "one size fits all"; instead regulators undertake a detailed assessment of the types of uncertainty that will be faced and consider and select the appropriate proportionate response to each type;[233]

(c) developing detailed guidance for the regulated company and its customers as to the way the mechanism will be implemented – this includes detail on the methodologies and processes that will be applied, the criteria that will need to be met for the mechanism to be triggered and the criteria the regulator will apply when determining the size of any allowed revenue adjustment;[234] and

(d) ensuring the robustness of the mechanism by including an appeal process for the regulated company and affected parties to challenge the application of the mechanism within the price review period.

26.9 Accordingly, in formulating the Price Control – for each element of expected cost subject to uncertainty – the Utility Regulator should have:[235]

(a) assessed whether it was appropriate to have employed an uncertainty mechanism;

(b) identified the different types of uncertainty faced by the Appellant;

(c) identified suitable mechanisms to deal with each circumstance; and,

232 CEPA Report, paragraph 3.2(i) **[IA1/1/24]**.

233 CEPA Report, paragraph 3.2(ii) **[IA1/1/24-28]**.

234 CEPA Report, paragraph 3.2(iii) **[IA1/1/28-29]**.

235 See section 2 of the CEPA Report **[IA1/1/13-20]**, for an explanation of the different types of uncertainty faced by regulated companies and how regulators manage these different types of uncertainty.

(d) selected the most appropriate mechanism for each taking account of the individual nature of the uncertainties involved.

26.10 Contrary to good regulatory practice, the Utility Regulator failed to apply this approach in assessing the extent of the costs that would have to be recovered and the impact on financeability in setting the Price Control. CEPA conclude that the Utility Regulator's management of uncertainty fails to guarantee the best interests of consumers because it will: [236]

> *…blunt incentives for SONI to deliver the right outputs for customers efficiently, innovatively, on time and when needed.*

26.11 In its 2010-2015 price control decision, the Utility Regulator determined that the Dt process should be used (to the exclusion of any other mechanisms) to permit the Appellant to recover uncertain costs. These tended to be one-off relatively minor costs as opposed to those associated with the delivery of the significant new activities. In the Appellant's experience, Dt claims accounted for approximately 10 per cent of the Price Control revenues – which, if the same "rule of thumb" were applied, would result in claims in the region of approximately £7 million in the context of price control allowances of £69 million. As a result of the Utility Regulator's Decision, however, the proportion of revenues to which the Dt mechanism applies has significantly increased to approximately 23 per cent. This is because the Utility Regulator has broadened the scope of the Dt mechanism to encompass a wide range of additional activities. This includes the costs associated with I-SEM and DS3 System Services – both Significant Projects – which together involve forecast expenditure of approximately £13.3 million (i.e. nearly double the expected level of Dt claims based on past experience).[237] Meanwhile, the proportion of "uncertain" revenues which are not funded under the Decision has increased to 35 per cent.[238] The failure to consider uncertainty holistically across the price control is contrary to good regulatory practice. For example, CEPA cites Ofgem's RIIO Handbook where Ofgem states that its objective is:[239]

> *…ensure every uncertainty mechanism is considered holistically in light of other mechanisms and the wider price control package.*

26.12 In addition, CEPA notes:[240]

> *there is no visibility of the revenues SONI may be allowed for major expenditure items which the business (including network planning pre-construction projects, I-SEM and DS3 implementation), with near certainty, will need to undertake during the control period. In fact, it is unclear if the single uncertainty mechanism can be utilised for all these costs given they are not specifically provided for in the SONI TSO licence (e.g. DS3) as Dt qualifying costs which can be submitted by SONI to UR during the price review. Even if these costs would fall under the definition of "other reasonable and efficient costs" that could be included in Dt there is still a significant amount of*

[236] CEPA Report, section 5.1 **[IA1/1/42]**.

[237] I-SEM costs of £11.4 million plus DS3 System Services costs of £1.9 million.

[238] This includes the costs of Network Planning, estimated to be in the region of £15-20 million.

[239] CEPA Report, footnote 25 **[IA1/1/26]**.

[240] CEPA Report, Executive Summary **[IA1/1/6]**.

uncertainty as UR will need to recognise these costs on an ad hoc basis instead of being clearly specified. This is despite these activities representing significant expenditure (c. £40m out of c. £69m total price control allowed revenues) being directly linked to specified output requirements for the period which represent substantial value for customers.

26.13 The high proportion of uncertain revenue which is only recoverable under the Dt or other unknown mechanisms directly affects the Appellant's ability to obtain finance as explained in AS1. There is also a lack of visibility for customers and other stakeholders in respect of these material funding decisions, contrary to the Utility Regulator's Principal Objective and the key principle of transparency in regulation.

26.14 The Appellant sees no reason why the Utility Regulator could not have provided for interim modifications of the Price Control to address cost uncertainty for the Significant Projects it is required to undertake i.e. not only I-SEM and DS3 but large scale PCNPs. Indeed, CEPA notes that:[241]

Generally the greater the proportion of allowed revenues expected to fall under the scope of an uncertainty mechanism(s), the more specific and tailored is the design of that regulatory mechanism.

26.15 This approach is commonly followed by other regulators. For example Ofgem in RIIO-TD1 developed a process to enable National Grid as the GB transmission owner/operator to recover the costs of delivering the "Strategic Wider Works" or "SWW" programme at a later stage during the price control when the extent and timing of costs could better be determined. Ofgem explained its rationale for this programme as follows:[242]

A number of large transmission projects are needed over the coming price control period…Several of these developments were not agreed as part of the RIIO-TD1 price control as the timing and costs of particular projects were uncertain at the time of the settlement. To help manage this uncertainty we introduced the SWW arrangements. The SWW arrangements provide flexibility by allowing TOs to bring forward projects when more information is available (rather than only allowing TOs to develop projects that were agreed at the start of the price control). This helps to manage uncertainty and ensure value for money for consumers by ensuring that network infrastructure projects are progressed at the most appropriate time.

26.16 The Appellant does not suggest that the SWW programme is directly analogous to the significant new activities it is tasked with delivering, not least because the costs involved in the SWW programme are on a much increased scale.[243] However, Ofgem's approach to uncertainties around the SWW programme is a good example of the appropriate consideration

241 CEPA Report **[IA1/1/27]**.

242 Ofgem "Strategic Wider Works (**SWW**)" Factsheet 125.

243 The Appellant notes that in the case of SWW, Ofgem did provide for expenditure relating to pre-construction works as an upfront *ex ante* allowance (please refer to Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, paragraphs 4.57-4.62 (https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf). The Appellant contends that the scale of the investments it will be required to make on PCNPs during the Price Control could be considered to impose an at least equivalent financial risk – relative to its balance sheet, its cost base and its business plan – to that which applies to National Grid under RIIO-TD1.

which should be given to the types of mechanism that regulators can put in place to manage uncertainty and of the approach that should be taken in making a selection, i.e. assessing the specific challenges faced by the regulated company having regard to its business model and seeking to implement measures that help address those challenges in a way that protects consumer interests.

26.17 The Appellant further sees no reason why the Utility Regulator could not have made provision under a separate licence mechanism (such as the ATSOt term) for the recovery of costs which are outside the Appellant's control. Such costs are suitable to be approved via an At tariff submission on a pass-through basis, rather than subject to an assessment within the Dt framework, and include items such as pension deficit repairs and mandatory fees such as ENTSO-E membership, inter-TSO compensations, and regional security coordination costs. This would ensure that such costs are recovered pursuant to a more efficient and streamlined process, and that the Appellant is not financially disadvantaged due to the pass-through and unavoidable nature of such costs.

26.18 In the Appellant's case, there is no evidence that the Utility Regulator considered:

(a) the greater levels of uncertainty the Appellant will face during the Price Control Period;

(b) the high proportion of uncertain revenues that it excluded from the Price Control;

(c) the different types of uncertainty the Appellant will face during the Price Control Period;

(d) the Appellant's ability to manage the extent of such uncertainties (and/or its degree of resilience) given its small size and significant responsibilities;

(e) the availability of different mechanisms to manage different uncertainty;

(f) the most the most appropriate mechanism for each taking account of the individual nature of the uncertainties involved; and

(g) specifically, the merits of introducing an interim modification process when dealing with the costs of Significant Projects (which amount to approximately £30 million and affect multiple allowances) which would have provided flexibility, helped manage uncertainty and ensured value for money for customers in addition to providing a right of appeal for relevant stakeholders.

26.19 Further, there is no evidence that any consideration has been given as to whether it is appropriate to utilise the Dt (or other unknown) mechanism to enable the Appellant to recover costs associated with the delivery of such complex projects where the costs are uncertain as to the scale involved or as to the quantity or quality of outputs and/or timing of delivery. Nor is there any evidence to suggest that the Utility Regulator had regard to the proportion of total revenues that were subject to uncertainty and whether this was consistent with its statutory duties, in particular its duty to secure the Appellant's financeability. The large revenues associated with future Dt (or other) requests provides one reason as to why certain inputs in the Utility Regulator's financial model differ significantly from the arrangements set out in the Final

Determination and Draft Licence Modifications.[244] This directly impacts the Appellant's financeability assessment.

26.20 The Utility Regulator's approach in selecting a single inappropriate and illogical uncertainty mechanism and the lack of clarity as to which costs are recoverable and which are not under the Dt mechanism is contrary to best regulatory practice and has resulted in the Appellant facing greater uncertainty than necessary in terms the revenues it is likely to receive from tariffs. Indeed, CEPA reports:[245]

> *Despite the statutory responsibilities and obligations of the UR, the proposed FD does not guarantee: the financeability of SONI – indeed, it attributes significant asymmetric risk to a small asset light business; nor the best interests of Northern Ireland customers – as how uncertainty will be managed will blunt incentives for SONI to deliver the right outputs for customers efficiently, innovatively, on time and when needed.*

26.21 The lack of certainty is also contrary to the interests of consumers and compromises efficiency contrary to the Utility Regulator's specific statutory duties to protect the interests of consumers and to promote efficiency and economy in the generation, distribution, transmission and supply of electricity, as it hinders the Appellant's ability to plan and ensure the ongoing development of the transmission system in Northern Ireland.

26.22 The degree of uncertainty, the extent of the revenues affected and the lack of coherent cohesive processes has already had a detrimental impact on the Appellant's financeability as the lack of transparency has knock-on effects for investors and for lenders, in particular by giving rise to concerns about revenue volatility as explained in detail in AS1. In summary, the degree of uncertainty faced by the Appellant impacts on the willingness of banks to lend it money, impacting its financeability. This means that the Appellant itself has limited ability to manage the uncertainty with obvious implications for the Appellant to efficiently deliver in the best interests of the consumer. The Appellant explains the fuller impacts of the Utility Regulator's failure to ensure the Appellant's financeability in Sections 15 and 16 of Part IV and in AS1.

26.23 Finally, there is a further ingredient adding to the uncertainty in relation to the application of Dt, and this lies in the definition of "Price Control Decision Paper" at paragraph 1.1 of the Final Licence Modifications".[246] In combination with paragraph 8.2(a), this has the effect of requiring the Appellant in making any Dt submission to "*take account of and give regard to*" the Final Determination and Decision "*as supplemented or amended by any further decision paper on [the 2015-2020 Price Control]*". This constitutes a form of "Henry VIII clause" in regulation, in that the Utility Regulator may, simply by publishing further decision papers, radically alter the expectations of all parties as to the use of Dt in future. This uncertainty in a matter as important as Dt is now in the regulatory scheme is undesirable and, it would seem, unappreciated by the Utility Regulator.

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244 Further discussion of the Financial Models can be found in AS1.

245 CEPA Report, Executive Summary **[IA1/1/9]**.

246 As above, the Appellant notes that the date of the Decision Paper referred to in the Licence is incorrect – it should be 14 March 2017 and not 10 March 2017. This error adds further unnecessary confusion.

27 Error 5: Failure to provide a suitable right of appeal concerning decisions regarding cost recovery for Significant Projects

27.1 The duty to provide for a right of appeal enshrined in the Third Package of European Energy Directives (IME3),[247] as implemented in Northern Ireland by the Gas and Electricity Modification and Appeals Regulations (Northern Ireland) 2015, is not satisfied if a significant element of expenditure is reserved for the regulator and abstracted from review by the CMA.

27.2 The general requirement to provide for an effective right of appeal derives from EU law. IME3 contained a requirement for Member States to ensure that National Regulatory Authorities (NRAs) are able to make autonomous, timely decisions about regulatory matters and that those affected by the NRAs' decisions have a suitable right of appeal to an independent body.[248] The (then) Department of Enterprise Trade and Investment (**DETI**) consulted in 2012 and set out its intention to follow the (then) Department for Energy and Climate Change (**DECC**) proposals in GB in relation to this aspect of IME3.[249] A further consultation paper, specific to the legislative proposals for the energy licence modifications and appeals process was published by DETI in January 2014.[250]

27.3 The new energy appeals regime – which applies to this Appeal – came into operation in Northern Ireland in February 2015.[251] This changed the legislative procedure by which the Utility Regulator can modify gas and electricity licences to enable regulated companies and third parties materially affected by its decisions to appeal to the CMA.

27.4 When the Utility Regulator consulted on licence modifications to give effect to the new appeals regime it explained that the new procedures were consistent with the requirements of IME3:[252]

> *The Third Package of European Energy Directives (IME3) contained a requirement for Member States to ensure that National Regulatory Authorities (NRAs) are able to make autonomous, timely decisions about regulatory matters; and that those affected by the NRA's decisions have a suitable right of appeal to an independent body.*

The Utility Regulator's Decision

27.5 The Price Control itself only takes effect by virtue of a licence modification decision. However, where the Utility Regulator makes a funding decision which takes effect through the Dt mechanism, this does not give rise to a licence modification, notwithstanding the significant revenues involved. Rather, an adjustment is made to the total annual revenue cap. This means

247 Article 37(17) of the Electricity Directive.

248 Article 35(5)(a) and Article 37(17) of the Electricity Directive.

249 DETI, "*Proposed Amendments to the Gas (Applications for Licences and Extensions) Regulations (Northern Ireland) 1996*", September 2012 (available at https://www.economy-ni.gov.uk/sites/default/files/consultations/deti/consultation_document__gas_licence_apps_regs__.pdf).

250 DETI, "*Consultation on legislative proposals for energy licence modifications and appeals*", 24 January 2014 (available at https://www.economy-ni.gov.uk/sites/default/files/consultations/deti/consultation-energy-licence-modifications-appeals.pdf).

251 The Gas and Electricity Modification and Appeals Regulations (Northern Ireland) 2015.

252 Utility Regulator, "Changes to Gas and Electricity Licences with regards to Appeals to the CMA, Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland)", April 2015, paragraph 1.1 (available at https://www.uregni.gov.uk/sites/uregni/files/consultations/Licence%20modification%20and%20Appeals%20consultation%20May%202015.pdf).

that the Appellant is unable to appeal the adjustment to the CMA (as the right of appeal to the CMA attaches only to licence modifications). The Appellant repeatedly raised this as a concern, as explained in BT1.

27.6 The Utility Regulator's response to the Appellant's concerns was that its view was that the Dt mechanism is an appropriate mechanism to deal with all types of what it considers to be uncertain costs on the basis that it has always used this mechanism and that it is possible to challenge decisions made under the mechanism:[253]

> *The mechanism is in the current Annex. Any rights which are available to SONI in respect of any decision made by the UR under the existing mechanism continue to be available in respect of any decision that may be made under the proposed modification.*

Why the Utility Regulator's Decision is wrong

27.7 It is wholly unclear what the Utility Regulator means by the statement that rights *"continue to be available"* to the Appellant because there can be no appeal to the CMA under these circumstances. If it means judicial review, this would be inappropriate: this is why Parliament has provided for an appeal to a specialist tribunal, the CMA, and in any event is in stark contrast to the Utility Regulator's proposal internally to permit a review of DIWE, as expressed in paragraph 41 of the Decision, where the Utility Regulator seems to be proposing a process "…*similar to the Competition Commission's determination for NIE Networks*".

27.8 Even if there is an equivalence between the role of Dt in the former licence and in the modified licence, the Utility Regulator has failed to address the fact that the proportion of costs now subject to the Dt mechanism is significantly greater than in previous price controls – approximately 35 per cent as compared with approximately 10 per cent. The right to appeal decisions on substantial revenues is of obvious importance to the Appellant and to its financeability. Moreover the fact that an appeal to a specialist body is possible is a spur to making good decisions in the first place, and its absence encourages the making of bad decisions.

27.9 The inability of the Appellant or third parties to appeal decisions relating to the costs of Significant Projects creates a degree of instability around the price control process, which negatively impacts the Appellant's financeability.

27.10 The Utility Regulator has confirmed the Appellant's understanding about the lack of recourse available to it in the event that it wishes to challenge a funding decision on the recovery of PCNP costs:[254]

> *Should SONI disagree with the UR's determination…the avenue of recourse that is open to a regulated company involves making a reference to the CMA in respect of the opening Regulatory Asset Base in the next price control period.*[255]

253 Decision Paper, paragraph 51 **[NOA1/18]**.

254 Letter from the Utility Regulator to the Appellant dated 30 September 2016, exhibited at **[BT1/66]**.

255 The Appellant notes that this does not make sense because Dt expenditure is not necessarily associated with the RAB.

Of course, where a company considers that a determination has been made unlawfully, it may bring a legal challenge against the determination as with any other such decision made by a public body.

27.11 It is of little comfort to know that errors made during the periodic review might be considered and might be remedied in the next periodic review, whenever that might be concluded, or that a reference could be made to the CMA at that time assuming first, that, as per the Utility Regulator's suggestion, the Dt in question resulted in a change to the RAB by the end of the period (or at all), and secondly, that a relevant licence modification would be made which alone would be subject to an appeal to the CMA. It is far from certain that such errors would be subject to appeal to the CMA. This is not only unsatisfactory, but for the reasons set out above, greater scrutiny of the application of Dt would serve to reduce errors. As for "*a legal challenge*", as stated above, the court is an inappropriate forum to debate such matters. In addition, in any event, many of these matters are not RAB related.

27.12 The Utility Regulator's decision to prevent the Appellant from being able to appeal material funding decisions to the CMA is inappropriate and contrary to the requirements of IME3, as well as being entirely out of step with good regulatory practice and in breach of natural justice, which requires that parties have a right to a fair hearing. In the context of an overall revenue allowance of £69 million, the costs of Significant Projects to be determined using the Dt mechanism and the, as yet unspecified, PCNP cost-recovery process are material. As previously explained, the costs of I-SEM are currently expected to amount to £11.4 million[256]; of DS3 System Services are expected to amount to £1.9 million and of PCNPs are expected to amount to £15-20 million. To remove such significant revenues from the *ex ante* framework directly delivers poor incentive properties for the Appellant to maximise efficiency as explained in BT1. Indeed, in the NIE Determination, the CC explained that its rationale for removing the Dt term from the NIE price control was that it gave NIE insufficient incentives to be efficient. This was the case even where the Dt was restricted in its application to a small proportion of costs:[257]

We found that the UR's ability to approve, on a case-by-case basis, additional costs to be recovered through NIE's revenue control (under provision (viii) of the Dt term of the price formula) operated against the public interest. The scope for approval of such costs is limited to a cost pass-through basis, which would give NIE insufficient incentives to be efficient and so exposed consumers to the risk of excessive costs.

27.13 It is not only the Appellant that is adversely affected by the Decision. The appeals regime ensures that not only the regulated company but also other persons whose interests are materially affected by a licence modification decision – including the General Consumer Council for Northern Ireland in the capacity of representing consumers – are able to bring appeals to the CMA.

27.14 The Utility Regulator's decision to use the Dt mechanism and the (as yet undefined) PCNP cost-recovery process to manage uncertainty means third parties are prohibited from appealing funding decisions – including those relating to Significant Projects – to the CMA. Indeed, it is arguable that interested third parties (including consumer associations and industry participants)

256 As explained in footnote 18 above, the I-SEM programme continues to evolve in terms of scale and scope, with costs expected to increase.

257 NIE Determination, paragraph 3.76

are particularly disadvantaged by the use of these mechanisms because of the lack of transparency given the process involves bilateral communications between the Appellant and the Utility Regulator which are not in the public domain. This means there is no public consultation and so third parties are not afforded an opportunity to review the Utility Regulator's proposals and to make representations on the same, which is a breach of the Utility Regulator's duty to act to further the consumer interest and is contrary to good regulatory practice.

27.15 While the Appellant recognises that a requirement to introduce a licence modification in respect of each and every funding decision is inefficient and wholly unworkable, it submits that where these funding decisions relate to materially significant and complex projects (such as in the case of Significant Projects) an interim review with the accompanying licence modification consultation is for the above reasons the most appropriate mechanism to employ.

27.16 Finally, the latitude given to the Utility Regulator in being able to dictate changes in the manner in which the Appellant should make claims in relation to Dt by reference to further decision papers, expands the area of unreviewable discretion vested in it.

28 Error 6: Failure to manage uncertainty by creating additional uncertainty through implementing an unworkable two-stage process

28.1 The Utility Regulator has created additional uncertainty through the incorporation of an unworkable two-stage approval process into the existing Dt mechanism and the suggestion that a similar process will govern cost recovery for PCNPs. As noted by Fintan Slye, the requirement to manage further and ongoing extensive regulatory interactions means: [258]

> *…there is the potential that SONI will need to spend nearly as much time managing the regulator as managing the business, something it has not been provided with resources by the Utility Regulator to do.*

The Utility Regulator's Decision

28.2 Under the previous price control, the Dt mechanism required the Appellant to submit claims to the Utility Regulator *ex-post* to recover unforeseen costs which it incurred above the total annual revenue cap during each year of the price control.

28.3 For the 2015-2020 Price Control, the Utility Regulator decided to modify the mechanism by introducing a two-stage approval process (which was not consulted upon in the Price Control but appeared in the Draft Licence Modifications) with the first stage involving the submission of a Dt claim for "pre-approval" up to a cap and the second stage involving the Appellant reporting the actual cost and any necessary adjustment being made within the K factor mechanism for variance. The Utility Regulator explained:[259]

> *Generally, upon review of a Dt claim submission the Utility Regulator gives approval of an allowance up to a cap. SONI is then obliged, at a later stage, to report the actual cost and any necessary adjustment is made within the K factor mechanism for the variance.*

[258] Paragraph 43, FS1 **[FS1/1]**

[259] Final Determination, paragraph 444 **[NOA1/12]**.

28.4 In practice, it is not clear to the Appellant how the Utility Regulator has sought to implement this two-stage process in the Licence. The Licence includes an amendment in the form of a new ADTSOt-2 term set out in paragraph 2.2(i), which is applicable in the event that actual costs incurred are lower than the allowance set pursuant to the Dt mechanism. The relevant adjustment factor is ADTSOt-2, which is defined as follows:

> *ADTSOt-2 means:*
>
> *1) where actual costs incurred by the licensee in relation to excluded SSS/TUoS costs and change of law in Relevant Year t-2 are less than the costs allowed for DTSOt, in Relevant Year t-2, the total of such actual costs;*
>
> *2) where actual costs incurred by the licensee in relation to excluded SSS/TUoS costs and change of law in Relevant Year t-2 are greater than the costs allowed for DTSOt in Relevant Year t-2, the total of the costs allowed for DTSOt in Relevant Year t-2.*

28.5 This not only confirms that Dt costs are now subject to an *ex post* approval process, in addition to an *ex ante* approval of a cap, but also that the Utility Regulator has determined that the Appellant should not benefit from any efficiency gain should actual costs be lower than the cap but is responsible for funding additional costs should actual costs be greater than the cap, even if efficient. This imposes an unwarranted asymmetric risk on the Appellant which the Utility Regulator has failed to take account of when assessing the level of returns.

28.6 The Utility Regulator has amended paragraph 4.8 of Annex 1 of the Licence requiring the Appellant for each Relevant Year of the Price Control to use its best endeavours to submit Dt claims by no later than 31 March preceding the start of the next year. In response to the Appellant's submissions that it would not be possible to submit claims for unforeseen costs ahead of time, not least because the Dt mechanism permits recovery of costs incurred, the Utility Regulator adjusted the licence provision to explicitly permit the recovery of costs <u>likely to be</u> incurred as well as costs incurred:

> *At various places with 8.1 we have included the text "(or likely to be incurred)", this is to clarify that the Dt claims [that] may be made are not only for costs that have already [been] incurred but also costs that SONI are likely to incur.*

28.7 These changes do not of course make it any more possible for the Appellant to identify unforeseen costs in advance.

<u>Why the Utility Regulator's Decision is wrong</u>

28.8 The two stage approval process is unworkable. The modifications fail to achieve the effect intended by the Utility Regulator. The approach is inconsistent with good regulatory practice, is disproportionate, and further hinders the Appellant's ability to recover its efficiently incurred costs, to ensure it is, and is able to demonstrate that it is, financeable for the purposes of funding.

28.9 It creates an unnecessary administrative burden for both the Appellant and the Utility Regulator. Given that the Final Determination already suggests that the Dt cost approval (capped pursuant to the Utility Regulator's *ex ante* review of the submission)[260] will be subject to a K factor adjustment mechanism in respect of any required corrections, incorporating a DIWE provision (see Error 7 below),[261] the two stage approval process adds an unnecessary level of administration which does not serve a clear purpose. The Utility Regulator already has the ability, through this mechanism, to disallow any inefficiently incurred costs as part of an *ex post* review process – it is therefore unclear what additional purpose the *ex ante* approval of a capped allowance serves.

28.10 The Appellant considers the two-stage approval process to constitute evidence of an overly intrusive and disproportionate approach to regulation, contrary to good regulatory practice regulation. Given that sufficient mechanisms exist within the Final Licence Modifications to carry out an *ex post* cost assessment, the Appellant does not consider that requiring the additional *ex ante* approval of uncertain costs is proportionate.

28.11 In respect of PCNPs in particular (as explained in connection with Error 4), the requirement to obtain the *ex ante* approval and allowable cap has no basis in statute or in the Licence. Prior to the transfer of the obligation to the Appellant, this ex ante approval may have been required to ensure any development decisions were independent of generation and supply consistent with IME3. However, this is not a concern in relation to the Appellant.

28.12 In the absence of clear criteria, a timetable, or appropriate mechanisms for approval, the requirement is destined to result in uncertainty and delay. Evidence of likely delay is provided in paragraph 324 of BT1, where Bill Thompson explains that in practice it can take over a year for the Utility Regulator to assess straightforward Dt claims and provide the necessary funding to the Appellant.

28.13 In summary, the two-stage approval process therefore compromises efficiency and certainty, and has the potential to hinder the Appellant's cost recovery, with significant adverse consequences for its financeability.

29 Error 7: Unjustified creation of uncertainty through failure to provide guidance on the application of the demonstrably inefficient and wasteful expenditure provision

29.1 The Utility Regulator has introduced a new provision into Annex 1 of the Licence to enable it to determine adjustments to the Appellant's maximum regulated revenue or RAB for the purpose of protecting consumers from exposure to any costs that it adjudges to be *"demonstrably inefficient or wasteful"*.

The Utility Regulator's Decision

29.2 The Utility Regulator sought to give effect to this decision through the introduction of the concept of "*Demonstrably Inefficient or Wasteful Expenditure*" (**DIWE**) to Annex 1 of the Licence, which is defined in paragraph 1.1 as follows:[262]

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[260] Final Determination, paragraph 444 **[NOA1/12]**.

[261] Final Determination, paragraphs 444-448 **[NOA1/12]**.

[262] Final Licence Modifications, Annex 1, paragraph 1.1 **[NOA1/18]**.

> *…expenditure which the Authority has (giving the reasons for its decision) determined to be demonstrably inefficient and/or wasteful, given the information reasonably available to the Licensee at the time that the Licensee made the relevant decision about that expenditure. For the avoidance of doubt, no expenditure is demonstrably inefficient or wasteful expenditure simply by virtue of a statistical or quantitative analysis that compares aggregated measures of the Licensee's costs with the costs of other companies.*

29.3 The Utility Regulator justified the inclusion of this provision on the CC's determination in *NIE* in which the CC proposed to introduce a similar DIWE provision. The CC in turn referred to Ofgem's Final Proposals for the T1 and GD1 price control reviews in which Ofgem reserved the right to disallow DIWE costs.[263] The concern of the regulator in each case was to ensure that all costs were being efficiently incurred and that the regulated company would deliver future savings for the benefit of consumers. This is clearly a reasonable objective which the Appellant supports but this does not obviate the need for the Utility Regulator to explain how the provision will apply.

29.4 In the Draft Licence Modifications, the Utility Regulator originally included a further provision which stated that the Utility Regulator would issue guidance as to the interpretation and application of DIWE according to which the term would be interpreted and applied, which the Appellant welcomed.[264]

29.5 However, following receipt of the Appellant's response to the Draft Licence Modifications, which requested that such guidance should be forthcoming immediately or, in any event, before the start of the Price Control Period,[265] the Utility Regulator withdrew its commitment to provide guidance stating:[266]

> *In including this term we had originally envisaged that the guidance would be published in parallel with the Final Determination. Unfortunately this has not been possible. We have therefore revisited our proposal and have decided not to proceed with the inclusion of paragraph 9.1.*

29.6 In its Decision Paper the Utility Regulator confirmed its intention to provide the necessary guidance but only when the DIWE provision is used.[267] As a result, no advance guidance is available to the Appellant which might at least provide some degree of predictability over the circumstances in which the Utility Regulator might reach such a determination. This statement therefore gives little comfort to the Appellant and investors given there is no suggestion that any consultation on the scope of the application of the DIWE provision will be undertaken prior to its use.

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263 NIE Determination, paragraph 5.101.

264 Draft Licence Modifications, paragraph 9.1 **[NOA1/13]**.

265 Letter from SONI to UR dated 23 March 2016, exhibited at **[RJM1/2]**.

266 Letter from UR to SONI dated 13 May 2016, point 17.2, exhibited at **[RJM1/3]**.

267 Decision Paper, paragraph 41 **[NOA1/18]**.

Why the Utility Regulator's decision is wrong

29.7 The Utility Regulator failed to explain how it would apply the DIWE provision in advance of its application, which is of limited value to the Appellant.

29.8 The effect of the Decision is that it is entirely within the Utility Regulator's discretion to apply the DIWE provision and reduce or remove funds from the Appellant. This is contrary to regulatory best practice particularly in light of the concerns raised by the CC that certain limitations ought to apply in terms of the scope of a DIWE clause:[268]

(a) first, the DIWE provision should not be applied with the benefit of hindsight – the regulator needs to determine that costs were inefficient or wasteful based on information reasonably available at the time; and

(b) second, high-level econometric models used for benchmarking purposes, while often producing useful estimates of a regulated company's expenditure requirements over a future period, do not (by themselves) demonstrate inefficient or wasteful expenditure; and

(c) third, the regulator should undertake a factual investigation to determine whether or not the spend was inefficient and should publish a reasoned decision explaining any adjustment to the maximum regulated revenue.

29.9 Given the CC's decision in respect of NIE's last price control can have no binding application to what the Utility Regulator does for the Appellant's Price Control, it was incumbent on the Utility Regulator in deciding to introduce the DIWE provision to put in place relevant safeguards.

29.10 It was unacceptable for the Utility Regulator to withdraw its original commitment to provide guidance on the application of the DIWE provision on the basis that it did not have time to write it. This failure leaves the Appellant without any certainty as to when, how and why the Utility Regulator might seek to adjust its revenues downwards to account for DIWE. Given the breadth of the clause – which applies to all costs including those to be recovered using the Dt process and those in respect of PCNPs[269] – the Utility Regulator is required as a matter of law to explain how it intends the provision to apply (given that the application of any DIWE mechanism is not subject to appeal to the CMA).

29.11 This additional uncertainty has added even more risk onto the Appellant which is already operating in a heightened risk environment due to the impacts which can be expected from the extensive change progressing within the industry, as explained in BT1.

30 Error 8: Unjustified creation of uncertainty through the introduction of the Qt adjustment

30.1 in the Decision the Utility Regulator introduced a new "Qt" adjustment into the price control formula at paragraph 2.2 of Annex 1 of the Licence.

268 NIE CC Final Determination, paragraph 5.106.

269 Final Determination, paragraph 455 **[NOA1/12]** – the Utility Regulator suggests that, in respect of pre-construction Transmission Loan/Capacity Related projects, only actual costs "*that are properly and necessarily incurred*" should be recovered, suggesting that the DIWE provision will similarly apply

The Utility Regulator's Decision

30.2 The Qt term was introduced in the Final Licence Modifications, and was not previously incorporated or consulted upon in the Final Determination or Draft Licence Modifications. Alongside the introduction of this term the Utility Regulator confirmed in its Decision that the Price Control would have retrospective effect on the basis that "*the effective start date of the price control set by the Decision is 1 October 2015*".

30.3 The Qt adjustment is defined in the Final Licence Modifications as:

> *…an adjustment to be applied to the maximum core SSS/TUoS revenue, which:*
>
> *(i) in Relevant Year t ending 30 September 2017 shall be the amount which is determined by the Authority and notified to the Licensee in accordance with principles set out in guidance provided to the Licensee and;*
>
> *(ii) in each other Relevant Year shall be equal to zero.*

30.4 Minimal explanation of the effect of this adjustment is provided in the accompanying Decision Paper. Paragraphs 20 and 21 simply state:

> *The licence modifications which are made will therefore have the effect of setting the maximum regulated revenue for the five year period from 1 October 2015 to 30 September 2020 (subject to any modifications made following further consultation on the matters noted in this decision paper).*
>
> *Accordingly, as the first year of the price control has passed, in order to ensure that the maximum revenue for this relevant year t is calculated/assessed on the basis of the price control that should apply we have included a new term (Qt) which makes the adjustment that is required (as determined by the UR).*

Why the Utility Regulator's Decision is wrong

30.5 The effect of this is that the Price Control will have retrospective effect but, as the Price Control contains within it elements which confer a significant discretion on the Utility Regulator, the power to make any adjustment to the maximum revenue cap for the year ending 30 September 2017 is correspondingly very wide.

30.6 The regime which the Appellant thought was in place consisted of the relevant tariffs which would be applied in the absence of the price control modifications coming into effect on the date originally planned. This arrangement was referred to in the Draft Determination and finally implemented on 5 August 2015. The effect of these arrangements was to restrict the permitted tariff to the latest year for which the tariff parameters were set in Annex 1 of the TSO Licence. The Utility Regulator justified this approach as being consistent with "*the Competition Commission's recommendation within their final determination for the NIE 'RP5' price control*".[270] At this time, there was no discussion of, or reference to, the possibility that the tariffs

[270] Utility Regulator, *SONI Transmission System Operator Licence – Proposed Licence Modifications Consultation Paper,* 29 June 2015 (available at https://www.uregni.gov.uk/sites/uregni/files/consultations/2015-06-29_SONI_Proposed_licence_modification_consultation_paper.pdf)

might subsequently be adjusted by reference to an additional term in the 2015-2020 Price Control formula as explained in BT1. Until the Appellant had sight of the draft decision paper in January 2017, it had no reason to believe that the arrangement described above would not continue. Indeed, it seems to run contrary to the Utility Regulator's subsequent statement in its decision paper of 10 March 2017, which gave effect to the I-SEM, in which it stated that:[271]

> *Other suggested additions or amendments to the existing licence conditions which were not subject to the consultation published on 16 December will not be modified within this decision;* ***this would be contrary to statutory process****.*

30.7 The arrangements consulted upon by the Utility Regulator and implemented on 5 August 2015, extended the permitted tariffs for the final year of the 2010-2015 price control until such time as a revised price control could be introduced. The Appellant understood that such tariffs would remain in place until such time as a new price control could be implemented. It is contrary to the principle of regulatory certainty for the Utility Regulator to now seek to introduce a Qt term with retrospective application – not least because the Appellant has submitted and received approval for tariffs on the basis of these interim arrangements.

30.8 The Utility Regulator failed to follow the process proscribed in the Electricity Order for introducing a licence modification and did not consult on either the intent or precise codification of this term. In particular, it failed to adequately explain how it intends to apply the Qt term, which given its scope raises serious concerns. In the absence of such explanation the Appellant has no certainty as to how the provision will be applied and in what circumstances tariffs can be recovered. The unreasonably wide scope of the term coupled with the Utility Regulator's apparent intent to apply the maximum regulated revenues on a retrospective basis means that the Utility Regulator has discretion to retrospectively adjust the tariffs which it has approved for 2015 - 2016 and to reduce or remove funds from the Appellant, thus adding to uncertainty over cost recovery, and creating additional financial risks.

31 Summary of Errors

31.1 The Utility Regulator's approach to dealing with uncertainty creates a new risk platform for the Appellant for the Price Control Period. This has clear implications for the Appellant's financeability and there is no evidence to date these implications were considered by the Utility Regulator when making its Final Determination. As stated in BT1:[272]

> *Ultimately there are a number of key areas, PCNPs and additional IS capex outputs which have effectively been omitted and where there is no clarity whatsoever. In respect of others, for example Dt, there is some sort of framework but one which is deficient in a number of respects whether through the cumbersome two-stage approval process or an absence of appeal rights. In other areas, such as DIWE and Qt, the regulatory framework which should be designed to reduce uncertainty in fact increases it and SONI has limited guidance, if any, on how the Utility Regulator might employ these terms.*

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271 Utility Regulator, "*Decision on Modifications to the SONI Market Operator Licence and SONI Transmission System Operator Licence, necessitated to implement the Integrated Single Electricity Market (I-SEM)*", 10 March 2017 (https://www.uregni.gov.uk/news-centre/notices-decision-modifications-soni-transmission-system-operator-and-market-operator)

272 Paragraph 356 of BT1, **[BT1/1]**

31.2 Together, the uncertainty errors have significantly increased the Appellant's risk profile, with a direct impact on the Appellant's ability to demonstrate its financeability and hence to obtain finance in order to ensure its ongoing financeability, at a time when the efficient delivery of significant outputs for the benefit of consumers is most required. Moreover, the lack of certainty compromises the Appellant's ability to perform its Network Planning activities as it is not adequately equipped with the resources necessary for fulfilling its obligations. This clearly operates against the interests of Northern Ireland consumers and does not promote efficiencies.

32 Summary of relief sought

32.1 The specific relief sought is set out in Part V of this Notice. In summary, the Appellant requests that the CMA grant the following relief to correct the Utility Regulator's errors:

(a) Error 2: Failure to provide a cost recovery mechanism for PCNPs

32.2 The Appellant requests that, in respect of the costs of any PCNPs (save for those which are Significant Projects which are dealt with under Error 4 below), the CMA codify in the Licence a revenue recovery mechanism that enables the Appellant to recover all of its reasonably and efficiently incurred costs. Proposed text for the licence modification is provided in Part V of this Notice.

(b) Error 3: Failure to provide a cost recovery mechanism for additional IS capital investment

32.3 The Appellant requests that the CMA modify Annex 1 of the Licence to include additional IS capex outputs as an additional category for recovery via the Dt mechanism. This ensures that the Appellant is able to deliver any additional required outputs for the benefit of consumers. Proposed text for the licence modification is provided in Part V of this Notice.

(c) Error 4: Failure to provide a suitable cost recovery mechanism for Significant Projects

32.4 The Appellant requests that the CMA modifies the Licence by requiring the Utility Regulator to conduct an interim review of the costs associated with any Significant Project (including PCNPs) for which an ex-ante revenue has not been provided and to make an upwards adjustment to the annual revenue cap accordingly. The Appellant also request that the CMA modify the Licence by requiring an interim review in respect of any amounts that the Authority, its SEM Committee, or the Licensee has proposed for pre-approval, where the forecast amount is greater than a materiality threshold of £1 million, and the Authority or its SEM Committee has approved an *ex ante* allowance greater than £1 million. Proposed text for the licence modification is provided in Part V of this Notice. In each instance the accompanying licence modification consultation would propose amendments to Table A and/or B of paragraph 2.2 (b), ensuring that there is a suitable right of appeal for the Appellant or third parties in respect of the Utility Regulator's cost decision.

(d) Error 5: Failure to provide a suitable right of appeal concerning decisions regarding cost recovery for Significant Projects

32.5 The Appellant considers that the specific concern about the lack of appeal rights in connection with Significant Projects will be addressed by the remedy proposed in respect of Error 4 above, as the right of appeal to the CMA is triggered by modification to the licence.

32.6 Separately, the Appellant requests that the CMA amend the definition of "Price Control Decision Paper" to delete limb (iii) (reference to supplementary papers). The CMA might also correct the date of publication of the Decision Paper to 14 March 2017. Or, in the alternative, given it is clear that the relevant documents giving rise to the Licence Modification are the Final Determination and the Decision Paper, this definition might be deleted altogether.

(e) Error 6: Failure to manage uncertainty by creating additional uncertainty through implementing an unworkable two-stage process

32.7 The Appellant requests the CMA to modify the Licence to ensure that costs which are not within the control of the Appellant can be submitted as part of the annual revenue submission to the Utility Regulator under the ATSOt component of the allowable revenues formula, rather than the Dt process, on a fully cost pass-through basis.

32.8 The Appellant also requests the CMA to modify the Licence to ensure that costs which continue to be submitted under the Dt mechanism should be submitted on an "as incurred" basis, and not for pre-approval of a revenue cap on an individual basis which is corrected or post-approved to amend that allowance to actual costs (if lower).

32.9 Proposed text for these licence modifications is provided in Part V of this Notice.

(f) Error 7: Unjustified creation of uncertainty through failure to provide guidance on the application of the demonstrably inefficient and wasteful expenditure provision

32.10 The Appellant requests that the CMA modify the Licence to reinstate the obligation on the Utility Regulator to provide guidance on the DIWE mechanism, following a public consultation as to the scope of the guidance. The Appellant also requests that the CMA require the CMA to implement such guidance in a reasonable timeframe (which the Appellant suggests should be no later than six months following the CMA's determination) and not to apply the DIWE mechanism until the guidance is in place. Proposed text for the licence modification is provided in Part V of this Notice.

(g) Error 8: Unjustified creation of uncertainty through the introduction of the Qt adjustment

32.11 The CMA is requested to remove all references to the Qt term in Annex 1 of the Licence.

PART IV – GROUND 3

The Inadequate Allowances Ground

33 Introduction

33.1 This Section of Part IV of the Notice concerns the Appellant's third Ground of Appeal, which concerns the allowances provided for the Appellant by the Utility Regulator (referred to as the **Inadequate Allowances Ground**, as defined in paragraph 4.3(c) above).

33.2 There are three separate types of allowance in respect of which complaint is made, which will be addressed in turn:

(a) failure to provide adequate payroll allowances for Network Planning staff;

(b) failure to provide adequate pension allowances; and

(c) failure to provide adequate capital expenditure allowances

Error (9) Failure to provide adequate payroll allowances for Network Planning staff

34 Overview

34.1 Error 9 concerns the Utility Regulator's failure to provide adequate payroll allowances[273] for the costs of eleven employees[274] who are required to undertake Network Planning activities, (as further defined in Error 2), in breach of its Financeability Duty.

34.2 All eleven employees have protected employment rights under the Service Provision Change (Protection of Employment) Regulations (Northern Ireland) 2006 (**TUPE**) which applied when responsibility for Network Planning transferred from NIE to the Appellant via a licence obligation. The Appellant cannot amend their terms of employment without their consent and therefore cannot reduce their salaries and associated benefits.

34.3 The Appellant requests that the CMA read by way of introduction to this topic:

(a) BT1 and FS1, which explain that the Appellant received assurances from the Utility Regulator that the payroll costs of these employees would be funded; and

(b) AS1, which explains how this error impacts the Appellant's financeability.

34.4 In summary, the Utility Regulator's error is as follows:

(a) Error 9(a): Breach of legitimate expectation - the Utility Regulator led the Appellant to expect that it would be funded for the full payroll costs of all protected employees, which had transferred from NIE via a licence obligation. The Appellant acted on the Utility Regulator's assurances to its detriment; and, further or alternatively

(b) Error 9(b): Incorrect methodology - the Utility Regulator erred in setting the payroll allowance by disregarding the application of a relevant legal obligation (TUPE), which it ought to have considered.

34.5 The errors in the Decision are exacerbated by the Utility Regulator's failure to include any detailed reasons or justification for its approach in the consultation documents or in the Decision, or to provide any meaningful response to the Appellant's submissions.

34.6 The Utility Regulator's failure to fund the full payroll costs of the eleven employees has created a funding gap of £[redacted] in respect of three opex employees and of £[redacted] for eight capex employees.[275] The cumulative shortfall is approximately £3,176,190 across the Price Control Period. Absent correction by CMA, the Appellant would be required to make up the funding shortfall or risk facing action in an employment tribunal (with associated cost, reputational and

273 Payroll allowances do not include pension costs. Error 10 addresses the inadequacy of the pension contributions.

274 Twelve employees originally transferred to the Appellant from NIE pursuant to the terms of the relevant transfer. However, one of these twelve employees subsequently retired in the 2014/15 financial year. The errors and requested remedies set out in this Notice of Appeal relating to this issue concern eleven TUPE employees, notwithstanding that various items of correspondence and supporting evidence refer to the original twelve employees.

275 These figures are redacted in the non-confidential version on the basis that they provide salary details for groups of employees which, given the small number of employees involved, could be "reversed engineered" so as to reveal individual salaries which are confidential.

resource implications) for breaching its employees' protected rights. This has a material adverse impact on the Appellant's financeability both now and in future price controls to the extent that the Utility Regulator's Decision sets a precedent it maintains going forwards, creating a perpetual deficit.[276]

34.7 Accordingly the Utility Regulator's Decision in setting the payroll allowances was wrong by reference to the statutory grounds detailed in Part III of this Notice, as summarised below:

(a) The Utility Regulator failed under sections 14D(4)(a) and/or (b) to properly have regard to and/or to give appropriate weight to its duties under Article 12(2)(b) of the Energy Order to have regard to the need to secure that licence holders are able to finance their regulated activities, as regards the Utility Regulator's failure to adequately provide for the Appellant's payroll allowance for the eleven employees.

(b) The Utility Regulator failed under section 14D(4)(a) to properly have regard to its duties under Article 12(5)(a) of the Energy Order to promote the efficient use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity, as regards the Utility Regulator's failure to adequately provide for the Appellant's payroll allowance for the eleven employees, which compromises its ability to deliver Network Planning activities.

(c) The Utility Regulator erred in fact by treating the eleven employees with protected rights in the same manner as other employees and by determining that the Appellant was capable of reducing the payroll allowances associated with the eleven employees (Article 14D(4)(c)).

(d) The Utility Regulator erred in law by failing to take into account a relevant consideration, that is to say the application of relevant legislation (TUPE) to the conditions of employment of eleven employees (Article 14D(4)(e)).

(e) The Utility Regulator erred in law by breaching the Appellant's legitimate expectation that it would be able to recover the payroll allowances for the eleven employees (Article 14D(4)(e)).

34.8 The Appellant requests the relief summarised below and set out in Part V of the Notice.

35 Background

35.1 The formal arrangements for the transfer of the Network Planning obligation from NIE to the Appellant were set out by the Utility Regulator in the following documents:[277]

(a) SEM Committee Preliminary Decision of 15 February 2013 (the **Preliminary Decision**) which concerned and granted the application made for TSO certification, subject to approval from the European Commission.[278]

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276 It also has a consequential adverse impact on other cost items, notably pension contributions, as explained in Error 10.

277 Further background to the transfer of Network Planning responsibilities is provided in BT1.

(b) EU Commission Decision of 12 April 2013, certifying the Appellant as the TSO for Northern Ireland (the **TSO Decision**).

(c) The Utility Regulator's public consultation on measures for the purposes of the EU Third Energy Package, including proposed licence modifications, published on 20 September 2013.[279]

(d) The Utility Regulator's decision paper containing the outcome of its consultation, published on 28 March 2014 (the **IME3 Decision Paper**).[280] The IME3 Decision Paper covered a range of topics, including specific measures to give effect to the TSO Decision. In particular, the Utility Regulator proposed licence modifications to transfer Network Planning activities from NIE to the Appellant, which the European Commission had determined would ensure consistency with the requirements of Article 9(9) of the Electricity Directive. The Appellant's modified licence was published on 30 April 2014, effective 28 March 2014.

(e) The Utility Regulator's public consultation published 22 January 2014[281] and subsequent decision of 27 March 2014[282] on the modifications required to amend the Transmission Interface Agreement (**TIA**) between NIE and SONI (as jointly proposed by them at the request of the Utility Regulator). A modified version of the TIA was approved by the Utility Regulator on 27 March 2014 to reflect the new arrangements, setting out the terms and arrangements between SONI and NIE relating to the provision of transmission services and outlining the respective responsibilities of, and activities undertaken, by each party.

(f) The Utility Regulator's Final Decision of 2 July 2014 on TSO Certification confirming that as of 26 June 2014 the Appellant was certified as TSO in Northern Ireland in respect of the transmission system, owned by NIE (the **Final TSO Decision**). This decision gave effect to the TSO Decision.

35.2 In addition to the above documentation, the Appellant and the Utility Regulator engaged in various meetings, discussions and correspondence between October 2013 and March 2014, for the purposes of ensuring that the transfer of Network Planning activities could be facilitated in the most efficient manner. A detailed description of this engagement is provided by Bill Thompson in BT1.

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278 This decision is exhibited at **[NOA1/2]**. Further background to the Appellant's engagement with the SEM Committee on this issue can be found in BT1.

279 Utility Regulator, "*Consultation on measures for the purposes of the EU Third Internal Energy Package",* 20 September 2013 (available at https://www.uregni.gov.uk/publications/consultation-measures-purposes-eu-third-internal-energy-package)

280 Utility Regulator, "*Decision Paper on measures for the purposes of the EU Third Internal Energy Package*", 28 March 2014 (available at https://www.uregni.gov.uk/publications/decision-paper-measures-purposes-ime3)

281 Utility Regulator, "*Modifications to Transmission Interface Arrangements (TIA) between NIE and SONI resulting from the implementation of the Third Energy Package (IME3)*", 22 January 2014 (available at https://www.uregni.gov.uk/consultations/consultation-proposed-modifications-tia-between-nie-and-soni-following-ime3)

282 Utility Regulator, "*Modifications to Transmission Interface Arrangements (TIA) between NIE and SONI resulting from the implementation of the Third Energy Package (IME3)*", 27 March 2014 (available at https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/UR_Decision_Paper_-_TIA_Mods_for_NIE_and_SONI.pdf).

35.3 A total of 22 roles (19 direct and 3 indirect) were identified as being attributable to the Network Planning function within NIE. When the transfer was implemented, twelve staff transferred from NIE to the Appellant. One employee subsequently retired, meaning that eleven transferring staff remain. Of the eleven transferring roles, three are considered to be opex in nature, with staff working on Phase 1 activities, with the remaining eight roles expected to be involved primarily in Phase 2 Capex projects or PCNPs. All eleven transferring employees are currently engaged full-time in activities associated with Network Planning as explained in Part D of BT1.

35.4 Prior to the implementation of the transfer and to allow it to assess its ability to accept the proposed licence amendment, the Appellant sought its own legal advice on the transfer arrangements. The Appellant was advised that TUPE applied and that as a result, the existing employment contracts of transferring staff would have to automatically transfer to the Appellant. In practical terms, this meant that any employees transferring from NIE to the Appellant would retain their existing terms and conditions of employment and the Appellant would have limited ability to amend such contracts.

35.5 The Appellant informed the Utility Regulator that is was advised that TUPE applied to the transfer. Given the implications in terms of needing to match the salaries of the transferring staff, the Appellant sought assurances from the Utility Regulator that it would be funded for the full enduring costs associated with the transfer of the licence obligation.

35.6 The Utility Regulator met with the Appellant on 6 March 2014 and confirmed that it would provide a letter of comfort setting out the principles for recovery of Network Planning costs. In BT1, Bill Thompson explains the importance of this meeting for the Appellant in terms of ensuring the costs of the Network Planning function were recoverable. The Appellant specifically sought reassurances concerning the need to recover the actual payroll costs of TUPE staff.[283] This included the future payroll costs of any staff transferring from NIE. The Appellant explained that it could only consent to the transfer upon receipt of such assurances.

35.7 The Utility Regulator wrote to the Appellant on 14 March 2014 to provide such comfort. It reassured the Appellant that any costs associated with the transfer would be recoverable pursuant to paragraph 6.3 of Annex 1 to the Licence (*Change of Law*). This sets out the requirement that the Utility Regulator ensure that the financial position and performance of the licensee is likely, so far as reasonably practicable, to be the same as if the relevant change of law had not taken place.

35.8 Having received such assurances, the Appellant sought to recover its costs of implementing the transfer and any additional costs arising during the remainder of the 2010-2015 price control. The Utility Regulator agreed to provide the Appellant with an additional allowance of £3.1 million[284] in order to allow it to fund the activity until 1 October 2015 and approved this in the tariffs. [285] The allowance included the full salary costs that the Appellant was now obliged to

283 See exhibit **[BT1/16]** to BT1, an email from Bill Thompson of SONI to Jo Aston of the Utility Regulator summarising the points discussed at the 6 March 2014 meeting.

284 The figure of £3.1 million includes a £0.5 million contribution into the Appellant's pension scheme to provide for accelerated deficit repair, as a condition of extending the pension scheme to NIE staff transferring under the TUPE arrangements.

285 The Appellant's SSS tariff submissions of 26 June 2014 were approved in their entirety in a letter from the Utility Regulator dated 1 August 2014 and titled "*Utility Regulator Approval of SSS Tariff for 2014-15*" **[BT1/48]**. The specific

pay. As explained in BT1, the Utility Regulator committed to assess and provide for any ongoing funding requirements as part of its price control review.

36 Errors

36.1 In its Business Plan of October 2014, the Appellant identified roles for Network Planning employees on the basis of the transfer. It included actual payroll costs in respect of the three opex employees within its overall payroll submission and assumed the payroll costs of the nine capex employees to be recoverable within the projected costs of the planned PCNPs. The Appellant assumed that the costs of all of these employees would be recoverable in full given the Utility Regulator's previous assurances and the fact that it had provided for this in the 2014/15 tariff in full.

36.2 In the Draft Determination the Utility Regulator indicated that it was making provision in its opex payroll allowance for 19 TUPE employees,[286] each at an average benchmark salary allowance. The benchmarking approach was consistent with that adopted for all other employees, and commonly applied across the 19 roles. No consideration was given in the Draft Determination to the Appellant's legal obligations concerning the individuals who had transferred under TUPE or to the fact that its actual payroll costs for the TUPE employees were higher than the average benchmark. This singular treatment of staff costs was inconsistent with the acknowledgement of the application of TUPE arrangements in the IME3 Decision Paper,[287] published just over a year prior to publication of the Draft Determination.

36.3 In reviewing the payroll costs, the Utility Regulator primarily adopted the ASHE Survey as a benchmark against which to compare costs. The Utility Regulator reviewed the roles in the ASHE Survey which it deemed to be similar to those identified in the Appellant. In particular, it explained that the ASHE data was used by Ofgem in calculating the direct and contract labour for RIIO-GDI and within the Data Communications Company (**DCC**) price control and described the ASHE data as "*an appropriate tool and methodology for use in determining this price control*".[288] This reference however fails to contextualise Ofgem's use of the ASHE data. For example, Ofgem noted in its consultation regarding the DCC Price Control 2014/15 that "*[w]e appreciate that benchmarking salaries using ASHE data in this way <u>has its limitations</u>, and must be treated with caution*" (emphasis added).[289] In the case of the DCC price control, Ofgem therefore employed ASHE data *only* as contextual information. Ofgem went on to explain that it uses ASHE data <u>to inform</u> benchmarking in the RIIO price control reviews, for example to understand regional variations in wages for the purposes of comparing the networks on a like for like basis,[290] which is not the same as applying the ASHE data as a benchmark across all categories of employees without regard to the circumstances of particular groups.

allowance of £3.1 million for Transfer of Planning Costs within the Bt term was also recognised and approved in a letter from the Utility Regulator dated 18 August 2015 and titled "*Utility Regulator Approval of SSS Tariff for 2015/16*" **[BT1/64]**.

286 Draft Determination, paragraph 91 **[NOA1/11]**

287 IME3 Decision Paper, paragraph 3.24.

288 Final Determination, paragraph 90 **[NOA1/12]**

289 Ofgem, DCC Price Control Consultation: Regulatory Year 2014/15, page 69.

290 Ofgem, DCC Price Control Consultation: Regulatory Year 2014/15, pages 69-70.

36.4 Notwithstanding the Appellant's more general concerns that the ASHE Survey did not offer an appropriate benchmark in the context of the salaries of the Appellant's other employees (i.e. for staff other than those whom transferred from NIE), as explained above and in Part D of BT1,[291] the Appellant submits that there was no reasonable explanation why the Utility Regulator decided to apply a benchmarking approach to the employees that transferred from NIE.

36.5 In its response, the Appellant strongly objected to Utility Regulator applying a benchmark assessment to the TUPE-protected staff, stating:[292]

> *SONI has no control over these costs (employment or pension) as TUPE and Protected Person legislation pertains. SONI advised NIAUR on numerous occasions in writing, prior to the transfer itself, that it could only take on the transfer on the basis that it could recover the costs it was inheriting by virtue of law. SONI cannot operate on a basis whereby it inherits liabilities by virtue of law (in the interests of overall industry structure) and that somehow these can be disallowed or reassessed. It is neither appropriate nor reasonable for NIAUR to determine that it will allow only a portion of these costs during 2015/2020.*

36.6 In the Final Determination, the Utility Regulator corrected its approach insofar as it recognised that only twelve individuals had in fact transferred across from NIE. It agreed with the proposed split in funding of roles between payroll opex (three employees) and capex projects (nine employees).[293] It did not, however, remunerate the Appellant for the full costs of these staff.

36.7 For the opex staff, the Utility Regulator included the three TUPE staff members in its overall payroll allowance which it set by reference to an average benchmark salary deduced from the Office of National Statistics (**ONS**) Annual Survey of Hours and Earnings (**ASHE**) (the **ASHE Survey**). The Utility Regulator explained that it considered it had undertaken a robust approach to undertaking a remuneration benchmarking exercise, explaining:[294]

> *As stated in the Draft Determination the Utility Regulator has reviewed the roles in ASHE which are similar to those identified in SONI, these include e.g. engineering professionals, electrical engineers n.e.c., IT specialist managers, IT project and programme managers, IT business analysts, architects and systems designers.*

36.8 The Utility Regulator made no reference as to what consideration, if any, it had given to the implications of TUPE for the Appellant, i.e. that it had to match their existing salaries paid by NIE. Although outside the scope of this Notice, it is not even clear how the Utility Regulator concluded that the ASHE Survey analysis was the appropriate benchmark for other (non-TUPE) staff given the Appellant's circumstances and the particular expertise and experience required to undertake their roles

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291 This refers to an independent report carried out by Towers Watson which examined and compared SONI specific pay and conditions to equivalent roles in comparator industries which the Appellant submits offered more fitting comparisons than the general ASHE Survey. This was provided to the Utility Regulator as Paper 3 of the Business Plan Submission and is exhibited as **tab 3 of [BT1/31]**.

292 SONI Response Appendix to NIAUR Draft Determination (of 2 April 2015), dated 18 May 2015, pages 8-9 (Exhibit [**BT1/40**]).

293 Final Determination, paragraph 76 **[NOA1/12]**.

294 Final Determination, paragraph 91 **[NOA1/12]**.

36.9 For capex staff, the Utility Regulator made no determination, stating only that project specific allowances would be provided through the new, and as-yet unspecified, "*pre-construction project approvals*" process.[295] As explained in Error 2, there remains significant uncertainty as to the specific mechanism through which such payroll costs will be recoverable.

36.10 In its response to the Final Determination the Appellant repeated its objections to the failure to take its TUPE obligations into account. It made several attempts to further explain its position to the Utility Regulator, as explained in Part D of BT1.

36.11 In the Decision Paper, the Utility Regulator explicitly acknowledged that the transferred staff gave rise to "*additional TUPE costs that are inherited from NIE Networks and are required to be covered within SONI allowances*".[296] Despite this, it refused to provide an appropriate *ex ante* payroll allowance. Indeed, it went so far as to suggest that it had already taken TUPE into account in its original analysis: [297]

> *…we acknowledge that the actual staff transferred are additional TUPE costs that SONI have inherited from NIE Networks and we have taken that into account, based on the age profile of the staff (some of the staff will be retiring within the price control period), we have determined that the costs allocated to these roles should be sufficient to cover the cost of the staff for this activity for the period.*

36.12 The Appellant cannot find any evidence of the Utility Regulator having taken TUPE into account when setting the payroll allowances in the Draft or Final Determination or in the Financial Model. The only reference to TUPE is a footnote in the Final Determination which references the legislation in full.[298] It is clear from the level at which the payroll allowances were set that the full salary costs of the opex TUPE staff were not granted.

36.13 The shortfall in funding for the opex staff amounts to £[redacted] over the Price Control.[299] This is based on the difference between the benchmarked allowance set out by the Utility Regulator and the actual TUPE costs that are being incurred.

36.14 As the ongoing payroll costs associated with the transferring staff were known during the Price Control process (i.e. they were quantifiable and the Utility Regulator was made aware that they were unavoidable pursuant to TUPE), it should have been a straightforward exercise for the Utility Regulator to clearly provide an *ex ante* payroll allowance for both the opex and capex staff, at their full TUPE value. In the Decision Paper, the Utility Regulator suggests that it did take TUPE into account when setting the payroll allowances for the opex staff but there is no evidence of this.

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295 Final Determination, paragraph 79 **[NOA1/12]**.

296 Decision Paper, paragraph 69 **[NOA1/18]**.

297 Decision Paper, paragraph 96 **[NOA1/18]**.

298 Final Determination, footnote 17 **[NOA1/12]**.

299 As explained in Part D of BT1, it is difficult to provide an exact figure given the discrepancies in allowances as stated in the Final Determination and that provided in the Financial Model **[NOA1/14]**. However, this figure is roughly calculated on the basis of a £[redacted] delta per annum between the average TUPE cost per employee (including National Insurance contributions) and the average payroll allowance per the Financial Model (£[redacted] plus the National Insurance delta of £[redacted] included in the Financial Model), which equates to £[redacted] during the Price Control for one employee or £[redacted] for three employees.

36.15 In respect of the capex staff, the Utility Regulator suggests that it will consider these costs as part of any separate assessment for PCNPs.[300] This provides little comfort given that in the absence of any codified cost recovery mechanism in the Licence, the Appellant has no certainty that all of its reasonably and efficiently incurred costs will be recoverable.

36.16 For capex staff the shortfall in funding is not known due to the failure of the Utility Regulator to provide an *ex ante* allowance to cover capex staff costs. Absent correction by the CMA as requested in this Notice, the Appellant now must seek to provide for known and unavoidable capex payroll costs over the Price Control Period, with no visibility over the recoverability of these costs. This amounts to an additional £[redacted] over the Price Control.[301] This is a significant sum yet there is no evidence that the Utility Regulator gave any consideration as to how this funding gap impacted the Appellant's financeability. Moreover, the lack of certainty compromises the Appellant's ability to perform its Network Planning activities, which cannot be in the interests of consumers and does not promote efficiencies. Together, these factors have significantly increased the Appellant's risk profile, with, as Aidan Skelly explains in AS1, a direct impact on the Appellant's ability to demonstrate its financeability and hence to obtain finance in order to secure its ongoing financeability. The implications of this inability to secure finance are discussed further at Part V of this Notice.

<u>Why the Utility Regulator's Decision is wrong</u>

36.17 The Utility Regulator was wrong not to have funded the full payroll allowances for the reasons explained below.

Error 9(a) The Utility Regulator breached the Appellant's legitimate expectation

36.18 It was the Utility Regulator's policy that the Appellant should take over responsibility for Phase 1 and Phase 2 Network Planning activities from NIE. From the outset of the discussions between the Utility Regulator and the Appellant surrounding the transfer the Appellant repeatedly sought assurances that it would be funded for enduring costs of the transfer, including the future payroll allowances of any staff transferring from NIE. The Appellant notified the Utility Regulator of its increased cost exposure arising from the transfer, and made it clear that it would not be in a position to accept responsibility for Network Planning activities unless it received appropriate funding.[302]

36.19 At a preliminary stage – some thirteen months before the transfer – the Utility Regulator acknowledged that there would be cost implications for the Appellant associated with taking on responsibility for Network Planning activities.[303]

[300] Decision Paper, paragraph 94 **[NOA1/18]**.

[301] This is calculated on the basis of £[redacted] multiplied by eight employees which equals £[redacted] per annum or £[redacted] over the Price Control Period. This figure includes relevant PRSI and NIC payments for the CapEx employees. Assuming the Utility Regulator were ultimately to apply the same ASHE benchmarking approach for the Capex employees for 100 per cent of their time then the funding shortfall would still be significant, amounting to £[redacted] over the Price Control (a total of £[redacted] for the Opex employees and £[redacted] for the eight Capex employees).

[302] Please refer to BT1 for an overview of the occasions on which the Appellant brought its concerns to the attention of the Utility Regulator in correspondence and in meetings between October 2013 and March 2014.

[303] See for example Annex 1, paragraph 9 of the Preliminary Decision dated 15 February 2013, in which the SEM Committee stated that "*…the transfer of Licence responsibilities will necessarily be reflected in the resources required to discharge the obligations of NIE and SONI and this will be reflected in their respective Price Control allowances determined by the Utility Regulator*" **[NOA1/2]**.

36.20 In a letter dated 22 October 2013, the Utility Regulator explicitly recognised that the transfer of staff would incur additional costs:[304]

> *The Utility Regulator has been informed that a number of NIE and Powerteam staff will be transferred to SONI by April 2014. The Utility Regulator accepts that these are new costs for SONI which have not been allowed for within the current price control and that appropriate additional allowance will be required.*

36.21 The Utility Regulator reassured the Appellant in its IME3 Decision Paper that the enduring costs of transfer would be assessed within the Price Control stating:[305]

> *SONI's next price control is due to be implemented on 1 October 2015. Any future cost implications for SONI will be assessed by the Utility Regulator as part of the 2015 SONI price control process. In the interim, there is a procedure whereby SONI may request additional costs.* (Emphasis added)

36.22 In particular, the Utility Regulator was aware that any transfer of staff would be subject to TUPE. In its IME3 Decision Paper it further explained:[306]

> *NIE and SONI have informed the UR that a transfer of staff from NIE to SONI will take place before April 2014 via TUPE arrangements. It is likely that between 15 and 20 'planning' staff will be involved in the transfer.* (Emphasis added)

36.23 On various occasions, the Utility Regulator demonstrated its awareness that the Appellant would be subject to legal obligations resulting from the transfer – including the costs of employees transferred under TUPE – and that these required specific consideration:

(a) in the meeting of 6 March 2014 (in which the Appellant highlighted that several staff would be transferring under TUPE) the Utility Regulator confirmed to the Appellant that it would provide a letter of comfort stating that its costs would be recoverable;

(b) in the Utility Regulator's subsequent letter dated 14 March 2014 (the **14 March Letter**),[307] the Utility Regulator explicitly stated that it would consider "*any relevant legal obligations resulting from this transfer"*;

(c) in its IME3 Decision Paper it recognised that there would be "*an increase in SONI's resource costs*"[308] because staff would be transferred from NIE;

(d) in its Final Determination, the Utility Regulator acknowledged that the transfer had significantly increased the Appellant's staff costs;[309] and

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304 Letter from the Utility Regulator to the Appellant, "*Expenditure associated with Transfer of Investment Network Planning from NIE to SONI*", dated 22 October 2013 **[BT1/10]**.

305 IME3 Decision Paper dated 27 March 2014, paragraph 3.23.

306 IME3 Decision Paper dated 27 March 2014, paragraph 3.24.

307 **[BT1/18]**.

308 IME3 Decision Paper dated 27 March 2014, paragraph 3.24.

309 Final Determination, paragraph 84 **[NOA1/12]**.

(e) in the Decision Paper, the Utility Regulator explicitly acknowledged that the transfer of the relevant staff resulted in "*additional TUPE costs that are inherited from NIE Networks and are required to be covered within SONI allowances"*.[310]

36.24 The Utility Regulator committed to ensuring that the Appellant would not be out-of-pocket as a result of taking on responsibility for Network Planning activities. In the 14 March Letter it specifically provided its assurance that "*efficient enduring costs associated with the transfer*" would be funded, citing the application of the Change of Law provisions in paragraph 6 of Annex 1 to the Appellant's Licence. In particular, the Utility Regulator sought to distinguish any costs arising as a result of legal obligations and to confirm that the Appellant would not be out-of-pocket as a result:[311]

> *We acknowledge your need for assurance that necessary additional and prudent costs, that are clearly identified by SONI, associated with effecting the arrangements, <u>as well as efficient enduring costs associated with the transfer</u> of investment planning from NIE to SONI will be met. <u>Such assurance is confirmed</u>.*
>
> *[…]*
>
> *We reiterate the requirement within paragraph 6 of Annex 1 of SONI's TSO Licence to '…ensure that the financial position and performance of the Licensee is likely, so far is reasonably practicable, to be the same as if the relevant change of law had not taken place'. <u>This will include consideration of any relevant legal obligations resulting from this transfer</u>.* (Emphasis added)

36.25 Given the assurances made by the Utility Regulator and its commitment to have regard to any costs resulting from legal obligations associated with the transfer, the Utility Regulator created a legitimate expectation that it would consider and appropriately remunerate the Appellant for the cost of the TUPE employees. The Appellant relied upon these assurances in agreeing to take on responsibility for Network Planning activities.[312] In particular, it relied on the Utility Regulator's promise to consider "*any relevant legal obligations resulting from this transfer*", believing this to include the legal obligation arising under TUPE to retain the existing terms and conditions of employment for the transferring employees. The Appellant was further encouraged by the Utility Regulator's letter of 2 May 2014, which reiterated the assurances given in the 14 March Letter and added:[313]

> *…we continue to stand by our commitment to engage with SONI over the coming months with a view to having both a price control and licence which is fit for purpose together with sufficient appropriate cost recovery reflected in the tariffs.*

310 Decision Paper, paragraph 69 **[NOA1/18]**.

311 Letter from Utility Regulator to the Appellant, "*Transfer of Investment Planning from NIE to SONI under IME3*", dated 14 March 2014 **[BT1/18]**.

312 For example, please refer to the Letter from the Appellant to the Utility Regulator, "*Transfer of Investment Planning from NIE to SONI under IME3*", dated 26 March 2014 **[BT1/19]**,which sets out the Appellant's commitment to proceed with the transfer, "*on the basis of [the 14 March] letter, and the assurances [the Utility Regulator] ha[s] provided….recognising that it is in everyone's interests that we are in a position to proceed*".

313 Letter from Utility Regulator to the Appellant, "*Disapplication Request – SONI TSO Licence Annex 1 Paragraph 5*", dated 2 May 2014 **[BT1/22]**.

36.26 It is clear from the above, as described in further detail in BT1, that the Appellant repeatedly reminded the Utility Regulator of its commitment to appropriately remunerate the Appellant for the actual payroll cost of the TUPE employees and of its continued reliance on the same. The Appellant operated on the understanding that the costs associated with the transfer would ultimately be recoverable in full as *ex ante* allowances under the Price Control.

36.27 Prior to the Price Control being set, any interim costs were recoverable under the Dt mechanism, in accordance paragraph 6.3 of Annex 1 to the Licence (Change of Law). The Change of Law provision requires the Utility Regulator to ensure that the financial position and performance of the licensee is likely, so far as reasonably practicable, to be the same as if the relevant Change of Law had not taken place.[314] In accordance with this provision, the Utility Regulator approved an additional allowance of £3.1 million under the Dt mechanism to allow the Appellant to fund its Network Planning activities until 1 October 2015 (which was intended to be the starting date for the next Price Control). This included provision to compensate the Appellant for the full payroll costs of the transferring staff for the relevant period.

36.28 The Appellant received no indication that the Utility Regulator would seek to adopt a different approach when setting the Price Control payroll allowances for Network Planning staff until the Draft Determination was issued. At this point, it became apparent that the Utility Regulator did not intend to appropriately remunerate the Appellant for the payroll costs of the transferring employees – contrary to the Appellant's legitimate expectations. The Utility Regulator acted contrary to its previous assurances and offered no justification or explanation for the change in approach.

36.29 The Appellant strongly opposed the proposed approach and took all possible opportunities to identify its concerns regarding the remuneration of TUPE staff costs, including:

(a) in its response to the Draft Determination, where the Appellant noted that the proposal:[315]

> *[f]ails to respect the legal obligations inherited by SONI on divestment and through the NIE transfer. This includes provision for the costs of personnel transferred under TUPE legislation and provision for persons who have been accorded 'protected persons' pension status under law. These obligations are absolute and the regulatory framework for SONI must respect them.*

(b) in a number of meetings with the Utility Regulator where revenue recovery for Network Planning activities was discussed;[316]

(c) in its "factual comment" response to a further draft determination provided by the Utility Regulator in December 2015, in which it explained:[317]

> *…these staff that transferred to SONI as part of the transfer of the Network Planning function have TUPE protection and as such SONI is liable for pay for their*

[314] In particular, please refer to the email from the Appellant to the Utility Regulator dated 4 July 2014 **[BT1/24/1]**, which again notes the application of the change of law licence provisions to the transfer.

[315] Response to Draft Determination, May 2015 at page 2 [**BT1/40**].

[316] Further discussion of the issues addressed at these meetings is set out at paragraphs 41 to 53 of BT1.

[317] SONI Response, Factual Review 2, 15 December 2015, page 7 [**BT1/55**].

contracted pay and pension arrangements regardless of NIAUR approved allowances and whether or not there are adequate project Dts requiring their input.

36.30 In the time between publication of the Final Determination and publication of the Decision, the Appellant engaged at length with the Utility Regulator with a view to achieving resolution on the fundamental problems identified within the Final Determination, one of which is the lack of remuneration of TUPE staff costs.[318] The Appellant has however been disappointed to see that the Utility Regulator has failed to resolve this straightforward issue in the Decision.

36.31 A public authority which has, by a promise or practice, conferred on a person a legitimate expectation of a procedural or substantive benefit may not frustrate that expectation if to do so would be so unfair as to amount to an abuse of power.[319] As explained by Fintan Slye, the Appellant relied, and continued to rely, on the assurances it received from the Utility Regulator in agreeing to take on responsibility for Network Planning activities:[320]

> *As part of the transfer of Network Planning SONI had a legal obligation to take on a number of NIE employees on the basis of their existing terms and conditions of employment, including pension entitlements. EirGrid was happy for SONI to take on the Network Planning function on the basis that the Utility Regulator would allow the full costs associated with these transferees under its price control supervision. I was personally involved in meetings with the Chief Executive of the Utility Regulator, Jenny Pyper, where these assurances were given, including the meeting of 6 March 2014, discussed in BT1.*

36.32 The Appellant has suffered, to its detriment, as a result of the Utility Regulator's breach of its legitimate expectation that it could recover these costs.

36.33 Having been aware of the application of TUPE to the transfer of Network Planning activities and having already reimbursed the Appellant for the costs of the transferring staff in full prior to the Price Control taking effect, the Utility Regulator simply needed to satisfy itself as to the extent of the on-going TUPE obligations and to set a commensurate *ex ante* allowance. This exercise should have been straightforward – reflective of the fact that these were known costs, and that the Appellant was legally obliged to pay the employees in accordance with their existing terms of employment and had no means to reduce these payroll allowances, at least until such staff retired or left the business for other reasons.[321] In respect of the capex staff, the Utility Regulator has failed in its Decision to take any such measure. While it asserts in respect of then opex staff that it has taken the TUPE obligations "*into account*",[322] there is no evidence that it

[318] Further detail on this subsequent engagement is provided in BT1.

[319] *Nadarajah v Secretary of State for the Home Department* [2005] EWCA Civ 1363, at paragraph 68, per Laws LJ:

> "*Where a public authority has issued a promise or adopted a practice which represents how it proposes to act in a given area, the law will require the promise or practice to be honoured unless there is good reason not to do so. […] Accordingly a public body's promise or practice as to future conduct may only be denied, and thus the standard I have expressed may only be departed from, in circumstances where to do so is the public body's legal duty, or is otherwise...a proportionate response…having regard to a legitimate aim pursued by the public body in the public interest.*"

For a more detailed description of the principle of legitimate expectations, please refer to Part III of the Notice.

[320] Paragraph 31, FS1 **[FS1/1]**

[321] As noted above, one such person has retired in the period since these submissions were made to the Utility Regulator.

[322] Decision Paper, paragraph 96 **[NOA1/18]**.

did so. If it did, there is also nothing to explain why it still proceeded to set an insufficient level of remuneration.

36.34 This error has a material adverse impact on the Appellant's financeability, as explained further in Ground 1, the Financeability Methodology Ground, and in AS1. The fact that the Appellant only took on responsibility at the direction of the Utility Regulator makes this even more egregious. Unless corrected by the CMA, there are also longer term implications from an increasing cost deficit as regards the Appellant's ability to finance its activities in the next price control period and beyond, because the Appellant has no choice but to fund the shortfall from the minimal returns permitted under the existing Price Control. This entails the risk of non-delivery (or delay) of outputs, which is clearly against the interests of Northern Ireland consumers.

Error 9(b) In any event, or alternatively, the Utility Regulator applied the wrong methodology by failing to have regard to relevant legal obligations

36.35 Quite apart from the failure to act in accordance with the Appellant's legitimate expectation that payroll costs for TUPE staff would be funded in full, the Utility Regulator erred in setting the payroll allowances for the Price Control by failing to have regard to the fact that the Appellant is subject to a legal obligation under TUPE concerning the terms and conditions of employment of eleven employees, including the level of their pre-existing NIE salaries.

36.36 It is undisputed that the eleven transferring employees were subject to TUPE protections, meaning the Appellant is not able to reduce or otherwise limit the payroll allowances of these staff or to otherwise amend the terms and conditions of their employment. The Utility Regulator's decision to disregard the Appellant's legal obligations under TUPE when setting the payroll allowances for these employees was an error because it constitutes a failure to have regard to a relevant consideration.

36.37 The Utility Regulator on several occasions demonstrated its awareness that the Appellant would be subject to legal obligations resulting from the transfer. The Appellant made regular submissions reminding the Utility Regulator of the application of TUPE, both before and during the Price Control process. The Utility Regulator itself recognised in the 14 March Letter that its treatment of the costs associated with the transfer must include "*…consideration of any relevant legal obligations resulting from the transfer*".

36.38 The Utility Regulator approved the recovery of the full salary costs insofar as they fell within the £3.1 million recovered by the Appellant under the Dt mechanism to cover the costs resulting from the transfer arising in 2014/15 prior to the Price Control allowances being set. However, it is clear from the Draft and Final Determinations that the Utility Regulator ultimately failed to have regard to the application of TUPE to the relevant employees, because it proceeded to apply the same benchmarking methodology used to set allowances for the three opex employees as it did for all other employees, and further failed to set any allowance **at all** in respect of the eight Capex employees. Further, the Final Determination did not contain any explicit consideration of TUPE.

36.39 As a matter of public law, the question of how much weight to attribute to a consideration is in the first instance a matter for the decision maker, which the Appellant acknowledges will permit a margin of regulatory discretion.[323] However, where undue weight, or inadequate weight, is attributed to any particular consideration, this decision should be held to be unreasonable and therefore unlawful. In determining whether or not the relevant omission has given rise to a decision based on a reviewable error, the test which the court will seek to apply is whether "*a consideration has been omitted which, had account been taken of it, might have caused the decision-maker to reach a different conclusion*".[324] The application of particular obligations of employment legislation to eleven of the Appellant's employees must be regarded as a relevant consideration which the Utility Regulator was obliged to consider in the context of setting the payroll allowance. Had the Utility Regulator properly turned its mind to consideration of TUPE, it would have had no alternative but to treat the three transferring opex employees as a separate category to which the application of a benchmark or reduction was wholly inappropriate, and to provide an *ex ante* allowance for the full remuneration of the payroll allowances associated with the eight transferring capex employees.

36.40 It should not be contentious to submit that, as a starting point in setting a price control, the regulator must consider the regulated entity's actual costs (as submitted), before considering whether it is appropriate to apply reductions to these costs in setting an allowance based on an efficient level of costs. Within this, the assessment of an efficient level of costs rests on the premise that the regulated business is able to control those costs.

36.41 Given the transferring employees had protected employment rights the Utility Regulator should have applied a different methodology to assessing their payroll allowances, and this should only have involved the Utility Regulator satisfying itself that the Appellant was indeed required to pay their full salaries and associated benefits. Had the Utility Regulator made these enquiries it would have found that the only legitimate means the Appellant had to reduce the payroll allowances of the eleven TUPE staff was by obtaining their consent to vary their existing terms and conditions of employment. The employees had no incentive to grant consent because their position was protected by TUPE.

36.42 Therefore, the Utility Regulator should have concluded that those costs were prudently and efficiently incurred. Its conclusion that benchmarking was appropriate and its subsequent application of the ASHE Survey data in respect of the transferring opex staff was in error, as would have been the application of any other benchmark.

36.43 The Appellant recognises that, in general, it would be inappropriate for the Utility Regulator to offer up a blank cheque on salary costs and that it is correct that, where appropriate, the Utility Regulator assesses costs to ensure they are reasonably and efficiently incurred. However, a reasonable assessment of payroll allowances in respect of this particular category of staff must start from the facts that the Appellant is subject to a legal obligation to pay – and therefore has no ability to reduce – inherited salaries and benefits, and that these obligations were imposed as a direct result of the Utility Regulator's actions to transfer the Network Planning function to the Appellant and to impose additional associated obligations in its Licence. Given the Appellant was bound by law to retain the terms of employment that the transferring staff had enjoyed from

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[323] The standard of review applied by the CMA is discussed at Part III of the Notice – the Appellant recognises that the CMA is not limited to traditional grounds of judicial review and is in fact entitled to review the merits of the Utility Regulator's decision.

[324] *R v Parliamentary Commissioner for Administration, ex parte Balchin* [1997] J.P.L. 917. This is the judicial test to be applied, and the CMA's review can of course be wider in scope, as discussed at Part III of the Notice.

NIE and that no "efficiencies" could be achieved – other than a total reduction in headcount for this function over that which NIE had allocated to Network Planning activities – it was only reasonable that such payroll allowances should be met in full.

36.44 The Appellant submits that the full TUPE costs should have been provided for in the payroll allowances for the three opex staff. Further, and given that the costs of capex staff are certain, the Utility Regulator could and should have made an *ex ante* allowance for the capex staff, or provided a separate and distinct mechanism, codified in the Licence, with unqualified assurances that these costs would be allowable in full. Alternatively, the Utility Regulator should have at the very least confirmed that the full TUPE costs in respect of payroll allowances for capex staff would be provided pursuant to its assessment of PCNP costs on a project-by-project basis at the appropriate time. Any subsequent payments made under the TIA to the Appellant would then be corrected pursuant to the K-factor adjustment mechanism within the Licence, which is designed for such a purpose. The Utility Regulator's assertion in the Decision Paper that it will "*consider these costs within any future [Dt] submissions*" is insufficient to provide the requisite comfort to the Appellant that it will be able to recover these costs.

36.45 This error has a material adverse impact on the Appellant's financeability, as explained further in AS1. The Appellant has no choice but to make up any shortfall for the eleven transferring employees or risk being taken to an employment tribunal (which would be a costly exercise both in time and money terms and harm its reputation as an employer). In the absence of this error being corrected, this deficit will continue in perpetuity having a material adverse ongoing impact on the Appellant's financeability.

36.46 Together, these factors have significantly increased the Appellant's risk profile, with a direct impact on the Appellant's ability to demonstrate its financeability and hence to obtain finance in order to ensure its ongoing financeability. Moreover, the lack of certainty compromises the Appellant's ability to perform its Network Planning activities as it is not adequately equipped with the resources necessary for fulfilling its obligations. This clearly operates against the interests of Northern Ireland consumers and does not promote efficiencies. The implications of this decision are discussed further in Part IV of this Notice.

37 Summary of relief sought

37.1 This Section of Part IV of the Notice summarises the relief sought in respect of Error 9. This is set out in detail in Part V of the Notice.

37.2 In summary, the Appellant requests that the CMA amend Annex 1 of the Licence so as to include provision for the full costs of the opex and capex TUPE staff.

Error 10: Failure to provide adequate pension allowances

38 Overview

38.1 Error 10 concerns the Utility Regulator's failure to provide adequate pension allowances.

38.2 Pension costs make up a significant proportion of the Appellant's payroll and hence operating expenditure. The Appellant operates an occupational defined benefit scheme, the SONI Limited Pension Scheme (the **DB Scheme**). Some of the Appellant's staff are members of the Scheme while others are members of a defined contribution arrangement. The **DB** Scheme is closed to new members. All members of the **DB** Scheme have protected rights pursuant to the Electricity (Protected Persons) Pension Regulations (Northern Ireland) 1992 (**Protected Persons Regulations**).

38.3 The Appellant requests that the CMA read by way of introduction to this topic:

(a) BT1, which explains the background to the Appellant's submissions on pensions funding and its engagement with the Utility Regulator on the issue of funding for pensions during the course of the price control review;

(b) AS1, which explains the impact of the Utility Regulator's errors in relation to pensions funding on the Appellant's financeability; and

(c) "SONI Limited: Opinion on defined benefit pensions aspect of price control 2015-2020", a report by Punter Southall (the **Punter Southall Report/JS1**)[325], which examines the Utility Regulator's decision in so far as it relates to pensions and provides an independent expert assessment of the Appellant's pension arrangements.

38.4 The Utility Regulator's error relating to pensions costs includes the following elements:

(a) Error 10 (a): Inadequate funding for ongoing contributions - the Utility Regulator applied an inappropriate methodology to setting an appropriate allowance for ongoing contributions to the Scheme creating a current estimate of a funding gap of £1,489,000 over the Price Control Period. The Utility Regulator failed to discharge its Financeability Duty by assuming wrongly that the Appellant could reduce the costs of the Scheme and by failing to consider the impact of the funding gap on the Appellant's financeability; and

(b) Error 10 (b): Inadequate approach to pension deficit recovery – it was wrong for the Utility Regulator to seek to put in place a new approach for pension deficit recovery without proper consultation or consideration as to whether this was appropriate for the Appellant or affordable. In particular, the Utility Regulator was wrong (i) to calculate the historical deficit up to a cut-off date of 31 March 2015 without consulting on this point and made errors in its calculation; and (ii) to treat the burden of funding any incremental pension deficit arising post the cut-off as a separate issue from the funding for ongoing contributions, to be consulted on at some, as yet, unspecified time in the future.

[325] **[JS1/1]**

38.5 The errors in, and inadequacy of, the decision in relation to pensions costs is exacerbated by the Utility Regulator's failure to include any detailed explanation in the published consultation documents or in the Final Determination or Decision of either its approach, its reasoning, or its consideration of the Applicant's submissions, and its failure to fully consider the characteristics of the DB Scheme.

38.6 Accordingly, the Utility Regulator's Decision in relation to pensions funding was wrong by reference to the statutory grounds detailed in Part III of the Notice, as summarised below:

(a) The Utility Regulator failed under Articles 14D(4)(a) to properly have regard to its duties under Article 12(2)(b) of the Energy Order to have regard to the need to secure that licence holders are able to finance their regulated activities, as regards the Utility Regulator's failure to make adequate provision for the Appellant to recover the cost of its contributions to the DB Scheme and its errors relating to pension deficit recovery.

(b) The Utility Regulator erred in fact by failing to distinguish that the members of the DB Scheme had protected rights and by treating them in the same manner as other non-protected employees (Article 14(D)(4)(c)).

(c) The Utility Regulator erred in law by failing to consult, to allow parties to make representations and to provide clear reasons for its decisions in relation to its decisions on ongoing contributions and pension deficit recovery (Article 14D(4)(e)).

38.7 The Appellant requests the relief summarised below and set out in Part V of the Notice.

39 Background

39.1 The current DB Scheme was established in June 2009, coinciding with the Appellant being acquired from NIE Networks by the EirGrid group in March 2009.[326] NIE was privatised in 1993.[327] At the time of privatisation, arrangements were put in place requiring the new private sector employer to continue to provide pension benefits for existing scheme members that were at least as good as those they had been receiving in the public sector. NIE was prevented from making changes to its scheme which reduced future pension accruals or increased employee contributions for these persons. These arrangements were codified in the Electricity (Protected Persons) Pension Regulations (Northern Ireland) 1992 (**Protected Persons Regulations**).

39.2 The Protected Persons Regulations provide protected persons with access to a defined benefits (**DB**) arrangement for future service on terms no less favourable than the terms applicable under the nationalised electricity scheme from which they transferred out originally. The Regulations also confer a right upon such protected persons to transfer their accrued benefits

326 The EirGrid acquisition of SONI was approved by the SEM Committee, which also approved associated licence changes – "Decision by the SEM Committee with respect to Modifications to be made to the SONI SO and MO Licence and to the EirGrid SO Licence", dated 26 February 2009 (available at https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-09-019.pdf). This followed a detailed consultation by the SEM Committee on the proposed acquisition – "Single Electricity Market Committee – The Proposed Acquisition of SONI Limited by EirGrid plc – A Consultation Paper" dated 18 December 2008 (available at https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-08-176.PDF).

327 In 1973 the Northern Ireland Electricity Service (**NIES**) was formed as a public utility to generate, transmit and supply electricity to Northern Ireland. In 1991, the company was incorporated as a government-owned public limited company, Northern Ireland Electricity plc. In 1992 its four power stations were demerged and sold. In 1993 the remainder of NIE (transmission, supply and retail businesses) was privatised as Northern Ireland Electricity.

from their current (and any former) schemes to any new scheme set up or nominated by a new employer.

39.3 When EirGrid acquired the SONI Business, approximately 30 employees transferring from NIE were protected persons. The Appellant set up the DB Scheme for these employees, consistent with its obligations under the Protected Persons Regulations. Given its obligations, the Appellant considers it appropriate that the pension costs it reasonably incurs are allowed for in full. As discussed in JS1, the Appellant has taken reasonable steps to reduce the costs of the DB Scheme. For example, subsequent to the transfer, the Appellant closed the DB Scheme to any additional members. This was a prudent decision designed to mitigate the high level of funding risk for both shareholders and customers associated with DB schemes, in particular the requirement to meet the pension promise of a pre-defined amount of income made to each member, regardless of how underlying investments have performed.

39.4 In 2014, exceptional circumstances arose – namely the transfer of the Network Planning Function – which required the Appellant to admit additional NIE protected persons to the DB Scheme (this option being less costly than setting up a standalone scheme). As the result of the transfer, the number of DB Scheme members increased to nearer to 40 members.

39.5 The terms of the DB Scheme are governed by a Trust Deed and associated rules. The trustees are required to approve the level of employer contributions to the DB Scheme.[328] The Appellant is required by law to perform a full actuarial valuation of the DB Scheme every three years.[329] The statutory deadline for completing each valuation and determining a new schedule of contributions is fifteen months after the effective date of the valuation.

39.6 Actuarial valuations were undertaken in March 2010[330] and March 2013.[331] For the 2010–2015 price control, the Appellant relied on the March 2010 valuation and requested an allowance of 28.1 per cent of pensionable salaries. The Utility Regulator funded the Appellant for the full allowance.

39.7 For the Price Control Period, the Appellant requested an allowance of 40.3 per cent based on the March 2013 valuation. The Utility Regulator set the allowance at 28 per cent of pensionable salaries – i.e. significantly below that required. The most recent valuation was produced in 31 March 2016 with the initial results showing an increase in the required contribution rate from 40.3 per cent to 44.4 per cent. Figure 15 provides a reconciliation of the results of the various actuarial documents.[332] The row headed "Total" in Figure 15 shows the percentage of pensionable salaries that the Appellant must contribute to fund the Scheme.

328 Further details about DB schemes in general and the Scheme in particular can be found in sections 3 and 6 of the Punter Southall Report **[JS1/1]**.

329 Pensions (Northern Ireland) Order 2005, section 203(1).

330 "SONI Limited Pension Scheme Focus Section – Report on the actuarial valuation as at 31 March 2010", prepared by Colin Mayger FIA, Barnett Waddingham LLP, dated 16 June 2011, annexed as exhibit **[AS1/1]** to AS1.

331 "SONI Limited Pension Scheme Focus Section – Report on the actuarial valuation as at 31 March 2013", prepared by Colin Mayger FIA, Barnett Waddingham LLP, dated 27 June 2014, annexed as exhibit **[AS1/4]** to AS1.

332 Extracted from paragraph 6.47 of Punter Southall Report **[JS1/1]**.

Figure 15: Summary of the assessed costs of providing DB Scheme benefits over time

	2010 valuation	2010 valuation (corrected)	2013 valuation (initial)	2013 valuation (final)	2016 valuation (initial)
Benefit accrual	29.5%	35.7%	44.6%	40.8%	44.9%
Death benefits	1.6%	1.6%	0.7%	0.7%	0.7%
Expenses	3.0%	3.0%	4.8%	4.8%	4.8%
Member contributions*	(6.0%)	(6.0%)	(6.0%)	(6.0%)	(6.0%)
Total	28.1%	34.3%	44.1%	40.3%	44.4%

39.8 The Appellant's requirement to fund the DB Scheme is documented in a schedule of contributions which is put in place following completion of each formal actuarial valuation of the Scheme. The current schedule of contributions was signed by the Appellant on 27 June 2014 and commits the Appellant to the contributions documented in it until 1 October 2023 or until such time as the schedule of contributions is replaced. The statutory deadline for completing the 2016 valuation and preparing a new schedule of contributions is 30 June 2017.

39.9 The financial assumptions applied to the DB Scheme must be set by reference to market yields at the effective date of the valuation. The assumptions adopted must be chosen prudently by virtue of Section 5 of the Occupational Pension Schemes (Scheme Funding) Regulations 2005.

40 Errors

40.1 The error in relation to pension costs involves two elements: a failure to provide adequate ongoing contributions and an incorrect approach to pension deficit recovery.

Error 10(a) Ongoing contributions

40.2 In its Business Plan the Appellant requested an allowance of 40.3 per cent for active members of the Scheme (including an allowance of 4.8 per cent for expenses and 0.7 per cent for death benefits). The Utility Regulator declined to provide the actuarially recommended contribution rate and increase the existing percentage contribution rate from 28 per cent stating:[333]

> *A number of options were considered by the Utility Regulator on balance the Utility Regulator has decided to maintain the 2010 – 2015 provision of 28 per cent throughout the five years of this price control. This is applied to the current level of DB members for the whole price control period. This provides SONI with some flexibility to manage its costs.*

40.3 The Utility Regulator's decision was based on having undertaken a benchmarking analysis. At the Draft Determination stage, this included considering the "Employer Standard Contribution Rate (SCR) contribution percentage payable by electricity companies in GB (at March 2010) by GAD"[334] (the 2012 GAD Report). The Utility Regulator noted that the average standard rate recorded in the 2012 GAD Report was only 26 per cent, and that this was significantly lower

333 Final Determination, paragraph 137 **[NOA1/12]**.

334 Draft Determination, paragraph 111 **[NOA1/11]**, referring to the Government Actuary's Department report to Ofgem on a review of network operators' (NWOs') pension costs published on 16 May 2012.

than 40.3 per cent rate applying to the DB Scheme. The Utility Regulator explained that it proposed to retain the 28 per cent contribution rate, which was marginally above the average standard rate, on the basis of the five year time lag since the GAD review. The Utility Regulator made no reference to the 2014 GAD Report[335] which was also available prior to publication of the Draft Determination and showed significantly increased average contribution rates,[336] although did refer to it in the Final Determination.[337] The Utility Regulator made no comment on the fact that the contribution rates examined in the GAD Report excluded administration expenses meaning they could not offer a like-for-like comparison. No justification was offered as to why it was appropriate to compare the Appellant's contribution rate against an industry average with no regard to the age profile of the scheme's membership or the fact that all members of the Scheme were protected persons.

40.4 In its Final Determination, the Utility Regulator revealed that it had also considered information from ONS[338] (the ONS Survey) which showed an all sector weighted average of 16 per cent for closed DB schemes. Again, no explanation was offered as to why this was a relevant comparator. DB schemes have a wide variety of benefit designs, with some significantly more generous than others. There are also many other factors which influence the ongoing contribution rate, including the investment and funding strategies adopted and the age profile of the membership.

40.5 A further reason given for not setting the allowance at 40.3 per cent was that the Utility Regulator considered the Appellant's protected benefits to be more generous than average and thought the Appellant should "manage" the level of contributions:[339]

> *The Trustees of SONI Ltd pension scheme review and agree the assumptions of the scheme. These assumptions would expect to include contributions from employees and employers. It is the responsibility of SONI Ltd to endorse and manage these as the employer.*

<u>The Utility Regulator's Decision</u>

40.6 As Aidan Skelly explains in AS1, the Utility Regulator made no effort to assess whether it was reasonable for the Appellant to reduce or control the level of ongoing contributions and took no account of the scale of the disallowance in the context of the underlying equity returns. The Utility Regulator took no account of the inability of the Appellant to change the benefits provided to scheme members given their protected persons status. Further, the Utility Regulator gave

335 Government Actuary's Department report to Ofgem on a review of network operators' (NWOs') pension costs published on 27 November 2014 (https://www.ofgem.gov.uk/ofgem-publications/91593/gadfinalreport-2014reasonablenessreview-pdf).

336 Government Actuary's Department report to Ofgem on a review of network operators' (NWOs') pension costs published on 27 November 2014 (https://www.ofgem.gov.uk/ofgem-publications/91593/gadfinalreport-2014reasonablenessreview-pdf).

337 Paragraph 136, Final Determination **[NOA1/12]**, which in turn refers to footnote 23 in the Final Determination **[NOA1/12]**, which references the November 2014 GAD Report.

338 Office of National Statistics Occupational Pensions Schemes Survey 2013, dated 25 September 2014.

339 Draft Determination, paragraph 113 **[NOA1/11]**.

the Appellant no credit for the fact that it negotiated a reduction in the contribution rate of 3.8 per cent with the trustees of the DB Scheme as part of the 2013 valuation process.[340]

40.7 In monetary terms the cost of funding ongoing pension contributions over the Price Control is significant. The Utility Regulator's decision to set the allowance at 28 per cent of pensionable salaries leaves the Appellant materially underfunded by £1,489,000[341]. It is not evident what consideration the Utility Regulator gave as to what impact the shortfall in funding would have on the Appellant's financeability.

Why the Utility Regulator's Decision is wrong

40.8 The Utility Regulator's decision not to fund the Appellant for its full costs of its ongoing pension contributions was wrong because:

(a) it applied the wrong methodology;

(b) it departed from its existing policy without any explanation or justification; and

(c) it failed to discharge its Financeability Duty.

40.9 These are explained in detail below.

(a) The Utility Regulator's flawed methodology

40.10 Two factors appeared to influence the Utility Regulator's decision to set the allowance at 28 per cent of pensionable salaries and not 40.3 per cent – its benchmarking analysis and the Appellant's ability to manage its costs. The Appellant considers that its approach to both issues was flawed and commissioned Punter Southall to provide an expert opinion on the Utility Regulator's approach and whether this was reasonable.

(i) Assessment of the Utility Regulator's benchmarking analysis

40.11 As explained above, the Utility Regulator relied on the ONS Survey and the GAD Report as containing data on comparable schemes when setting the Appellant's pension allowances. No explanation is given as to why these constituted relevant benchmarks.

40.12 It is unclear why the Utility Regulator considered the ONS Survey data to offer a useful comparator given:

(a) it was based on an all sector average, whereas the nature of the Appellant's business is very different most other regulated business, let alone businesses in the wider economy;

340 Paragraph 6.59 of the Punter Southall Report **[JS1/1]**.

341 This figure is based on (i) actual salary data as at 1 April 2016 (as opposed to the benchmarked salaries applied by the Utility Regulator as referenced in Error 9); (ii) 2013 valuation of contribution rates which includes 4.8 per cent expenses allowances and 0.7% allowance for the accrual of death in service benefits (i.e. 40.3 per cent rate); and (iii) an assumption that members retire in line with the assumption in the 2016 valuation. This includes assuming immediate retirement where members are already past their assumed retirement age.

(b) it was based on private sector schemes only, which on average tend to offer less generous benefits;[342] and

(c) it is highly unlikely that these schemes would have included a significant proportion of members with protected rights (which are particular to certain privatised industries such as electricity, rail, coal, London transport and nuclear decommissioning), whereas all members of the Scheme are protected persons under law.

40.13 Given these differences, the Appellant submits that it was illogical for the Utility Regulator to use the all sector rate as its starting point. Starting in the wrong place clearly magnifies any increase in contribution rates. The Utility Regulator's low base – an all sector contribution rate of 16 per cent - almost inevitably meant any contribution rate significantly in excess of this would appear unreasonable in circumstances when it is not. The Appellant's request for a 40.3 per cent contribution (including all additional costs and expenses) was always going to appear high given the stark difference of 24.3 percentage points between this and the all sector rate.

40.14 Punter Southall confirms that the characteristics of the DB Scheme are such that the average private sector scheme is not comparable: [343]

> *SONI is unable to change the level of benefits that the Scheme provides for its current active members who are all Protected Persons (i.e. their benefits must be maintained at the pre-privatisation level for both past and future service). As such, the cost of providing Scheme benefits is likely to be significantly higher than the cost of the average private sector DB Scheme.*

40.15 The use of ONS Survey data was therefore inappropriate and illustrative of the Utility Regulator's flawed methodology.

40.16 The Utility Regulator also placed considerable weight on the 2012 and 2014 GAD Reports.[344] A detailed assessment of the Utility Regulator's approach and an assessment of the relative weight that it should have afforded to the GAD Reports is provided in JS1[345]. Importantly, Punter Southall notes that the 2014 GAD report explicitly cautions against its use as a general benchmark: [346]

> *This is an important consideration which the author had deemed it necessary to alert readers of the report to in the introduction and should not be overlooked. The author expresses the view that it is not appropriate to simply benchmark one DB Scheme against another, highlighting that one must consider the differences between those DB Schemes, the way their assets are invested and the way in which they are funded.*

40.17 One of the notable differences between the Appellant's position and the contribution rates shown in the GAD Reports is that these are stated to be exclusive of administration expenses

342 Paragraph 6.33 of the Punter Southall Report, **[JS1/1]**.

343 Paragraph 6.34 of the Punter Southall Report, **[JS1/1]**.

344 Given the lack of detail as to which aspects of the 2014 GAD Report the Utility Regulator relied upon, the Appellant assumes that both GAD Reports were influential.

345 Paragraph 6.61 onwards of the Punter Southall Report, **[JS1/1]**.

346 Paragraph 6.73 of the Punter Southall Report, **[JS1/1]**.

and pension protection fund (PPF) levies. The 40.3 per cent contribution rate that the Appellant must meet includes an allowance of 4.8 per cent of pensionable salaries towards administration expenses. As such the underlying cost of future benefit accrual which is comparable to the figures in the GAD Reports was 35.5 per cent of pensionable salaries. As explained in JS1, Table 7 at page 41 of the 2014 GAD report which summarises *"Licensees' schemes funding positions as at March 2013"* revealed contribution rates ranging from 28 per cent at the lowest end to 58 per cent at the highest end[347]. Punter Southall explain that when viewed with this context, the Appellant's contribution rate at the same date of 35.5 per cent (excluding administration costs) is well within the range for Licensees' schemes and by no means at the top end.

40.18 The Utility Regulator should not have paid any regard to the 2012 GAD report and the underlying analysis upon which it was based given the historic nature of this data. In its Draft Determination, the Utility Regulator refers to evidence from the 2012 GAD Report that *"the electricity schemes' SCRs lie between 24 per cent and 28 per cent".* This relies upon data entries from 31 March 2010. By relying upon this report, it omitted to take into consideration various macroeconomic factors which affected all pension schemes between 2010 and 2013. Further, the Utility Regulator failed to provide any explanation as to why it had not looked at the more recent GAD report published in November 2014. Given the Draft Determination was not published until April 2015, there was no excuse for not using the more recent data.

40.19 To the extent either GAD Report could be said to offer relevant comparators the 2010 figures are in fact consistent with the Appellant's contribution rate having been submitted and set at 25.1 per cent (excluding 3 per cent for administration costs) from 2010 (although as explained above cannot provide any indication of what an appropriate rate should now be for the 2015-2020 price control). In addition, the current contribution rates are well within the range for funding rates set out in the 2014 GAD Report. A more rational methodology, however, would have compared the DB schemes of regulated business involving protected persons (or quasi-protected persons) as a benchmark, and then adjusting that benchmark figure based on factors which are specific to the Appellant's business.

40.20 Punter Southall explains that a key factor which the Utility Regulator omitted to take account of is the comparatively small size of the Scheme and the impact this has on administration costs. Such costs are to a large extent fixed, so it is inevitable that these costs are proportionately larger for the Scheme than for those attributable to the larger organisations covered by the ONS Survey and GAD report. Punter Southall notes:[348]

> *There are significant regulatory and compliance costs associated with the administration of a DB Scheme. Some of those costs do not vary directly in proportion to the size of the DB Scheme. As a result, for smaller DB Schemes the expenses can be significant in relation to their pensionable salaries of active members…*

40.21 A further key relevant consideration that the Utility Regulator should have taken into account is the age profile of the current active members of the DB Scheme. Punter Southall describes this as unusual in that, as at the date of the last formal actuarial valuation, the average age of the

347 Paragraph 6.61 onwards of the Punter Southall Report, **[JS1/1]**.

348 Paragraph 6.65 of the Punter Southall Report, **[JS1/1]**.

DB Scheme's active membership was 54.1 (weighted by liability). On average, the term to retirement is seven years, whereas in comparable schemes it tends to be ten to fifteen years. The shorter the time to retirement, the higher the cost of future benefit accrual – a factor which the Utility Regulator has ignored.[349]

40.22 As explained, the Appellant was legally obliged in 2014 to provide the transferring employees with access to a DB arrangement on terms no less favourable than those offered by NIE. Given the costs of setting up a comparable scheme, the most cost effective option was to permit seven new protected persons to enter the DB Scheme[350] (leading to more than a 20 per cent increase in the number of members) in connection with the Network Planning Transfer. There is no evidence that the Utility Regulator took into account the implications of the transfer.

40.23 Finally, Punter Southall notes that the Utility Regulator appears to have entirely disregarded the formal report on the actuarial valuation of the scheme as at 31st March 2013 which was prepared based on an analysis of factors which are specific to the Appellant. This report was prepared by Barnett Waddingham on the instruction of the DB Scheme trustees. It provides detailed justifications as to why a 40.3 per cent contribution rate is required to maintain the DB Scheme and avoid the potential requirement for deficit recovery. The Utility Regulator makes scant reference to the Barnett Waddingham actuarial report in its Final Determination merely noting that:[351]

> *The Appellant advises the sharp fall in gilt yields between 2010 and 2013 as being the major factor in the increase in the on-going service cost from 28% to 40% applied in mid-2014.*

40.24 The Utility Regulator appeared to ignore the fact that the contribution rate was set after negotiation between SONI and the DB Scheme's trustees, acting on actuarial advice – the Appellant was not "advising" but merely reporting the information contained in Barnett Waddingham's report.[352] No analysis or commentary was provided by the Utility Regulator in the Draft or Final Determinations or subsequently to explain what weight, if any, it afforded to the actuarial report.[353] Nor did the Utility Regulator give any explanation as to why it concluded that the 40.3 per cent contribution rate which the actuarial report recommended was wrong or irrelevant.[354]

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349 Paragraph 6.35 of the Punter Southall Report, **[JS1/1]**.

350 Or to set up a comparable parallel scheme at higher cost.

351 Final Determination, paragraph 133 **[NOA1/12]**.

352 Punter Southall confirms the method and assumptions adopted for the formal actuarial valuation of the Scheme to be fairly typical for a DB scheme in the UK. Paragraph 6.36 onwards of the Punter Southall Report, **[JS1/1]**.

353 In the Draft Determination at paragraph 110, the Utility Regulator did comment that the actuarial assumptions underlying the 2013 valuation were more prudent than those underlying the 2010 valuation. While this statement did not appear in the Final Determination, Punter Southall nevertheless disagreed with this assertion, finding that the 2013 assumptions were arguably less prudent than those adopted in 2010 (Paragraph 6.46 of the Punter Southall Report, **[JS1/1]**). More prudent assumptions typically raise costs leading to worse outcomes for consumers.

354 An error has recently been discovered in the 2010 actuarial valuation meaning the costs to the Appellant should have been 34.8 per cent as explained in paragraph 6.50 of the Punter Southall Report, **[JS1/1]**. This perhaps goes some way to explain the "leap" to 40.3 per cent from 28.1 per cent – a factor which may have influenced the Utility Regulator's decision had the information then been available. However, the main relevant consideration remains that the Appellant is obliged by law to meet these costs and has done everything reasonably possible to reduce them.

(ii) Assessment of the Appellant's ability to manage its costs

40.25 The Utility Regulator assumed that the Appellant could manage any ongoing contribution costs that it was not funded for.[355] In Punter Southall's expert opinion, this was not a fair assumption.[356] Punter Southall suggests that the Utility Regulator failed to pay sufficient regard to the Appellant's particular circumstances:[357]

> *SONI is unable to change the level of benefits that the Scheme provides for its current active members who are all Protected Persons (i.e. their benefits must be maintained at the pre-privatisation level for both past and future service).*

40.26 As Punter Southall explains, all members of the DB Scheme are protected persons under the Protected Persons Regulations. While the Appellant could technically reduce benefits provided by the Scheme for future service it could only do so if the members consented to their benefits being reduced. All of the members of the DB Scheme transferred from NIE and would likely have known that their pension rights were protected by law. It is hard to see what incentive Members have to agree to a reduction in their benefits. The Appellant is effectively prevented by law from reducing the future pension accruals of protected persons or increasing their employee contributions and must continue to provide benefits on the current terms to all remaining active members until such time as they retire or leave the DB Scheme. The Utility Regulator noted this fact but failed to accord it sufficient weight when conducting its assessment.

40.27 In fact, as Aidan Skelly attests in AS1, had the Utility Regulator conducted a thorough enquiry this would have revealed that, notwithstanding the limitations on its ability to manage the costs of the DB Scheme, the Appellant has consistently sought to control and reduce the costs wherever possible through the implementation of prudential measures including:

(a) successfully transferring from an RPI-based to a CPI-based pension indexation, reducing the employer contribution rate by 6.5 per cent of pensionable salaries;

(b) not consented to the payment of any unreduced early retirement pensions from the DB Scheme or made any DB Scheme member redundant where it would trigger the right to an unreduced early retirement pension, thereby increasing the cost of providing the member's pension;

(c) taking steps to avoid setting up a second DB pension scheme for the seven TUPE transferees who were protected persons under the Protected Persons Regulations, as this would have led to greater administration costs being incurred; and

(d) maintaining the closure of the scheme to new entrants (with the exception of the seven network planning employees that the Appellant was legally required to admit or otherwise provide the benefits for which mirrored the DB Scheme's provisions); and

(e) negotiating with DB Scheme trustees to seek concessions concerning the funding assumptions following the initial results of the March 2013 actuarial valuation (which

355 Draft Determination, paragraph 113 **[NOA1/11]**.

356 Paragraph 6.31 onwards of the Punter Southall Report, **[JS1/1]**.

357 Paragraph 6.34 of the Punter Southall Report, **[JS1/1]**.

revealed that the cost of future benefit accrual – net of fixed member contribution and including the allowance for administration expenses – was 44.1 per cent) reducing the overall costs of future benefit accrual to 40.3 per cent of pensionable salaries.

40.28 The lack of any enquiry by the Utility Regulator meant it failed to understand the limitations faced by the Appellant or to credit the Appellant for taking all reasonable steps to manage its costs.

40.29 The Appellant submits that had the Utility Regulator made these enquiries it could have satisfied itself that the Appellant's ability to manage its costs was extremely limited and that the Appellant had done everything it could in the circumstances to reduce its exposure.

40.30 In addition, the Utility Regulator's decision to set the contribution rate against benchmarked pensionable salaries rather than actual salaries was further evidence that it failed to properly assess the Appellant's ability to manage its costs. Punter Southall criticises this decision, stating that the appropriate allowance for future benefit accrual in the DB Scheme, expressed as a percentage of pensionable salaries, should be applied to the actual (and projected future) pensionable salaries of Scheme members rather than some lower amount, such as the salary of the average SONI employee or the average salary of a group of individuals working in a similar business.[358] In short, the protections afford to Scheme members means a narrow, focused, approach is required.

(b) Departure from existing policy

40.31 The Utility Regulator's failure to remunerate the Appellant in full was a clear departure from its earlier policy and practice. No explanation was provided for this change, nor can there be any rational basis for it given that the Appellant's legal obligations under the Protected Persons Regulations have not changed. The only relevant change that has occurred in between the price controls is the scale of those obligations given that the Appellant was required to take on a further seven protected persons in 2014, increasing the number of DB Scheme members to 40. The change in the required contribution rate was due to circumstances outside of the Appellant's control.

40.32 By way of background, the 2010-2015 price control was the first price control where the Appellant's pension costs were accountable under a separate SONI pension scheme, following divestment from NIE. The Utility Regulator recognised that ongoing pension costs formed an integral part of the Appellant's labour costs and determined that these should be treated as payroll costs and included in the company's allowance for operating expenditure.

40.33 In a 2011 consultation paper, the Utility Regulator proposed to "*reduce SONI's proposed Pensions allowance (ongoing costs) from £6.1m to £2.4m and will allow 100% deficit recovery over a 15 year period*".[359] In its consultation response, the Appellant emphasised:[360]

> *The personnel within the Defined Benefit (DB) scheme have " protected persons" status conferred upon them at the point of privatisation of NIE. These costs are therefore not*

358 Paragraph 6.79 of the Punter Southall Report, **[JS1/1]**.

359 "Utility Regulator Consultation Paper – SONI Price Control 2010–2015", dated 14 January 2011, page 28.

360 SONI Ltd Price Control Response 4 March 2011, page 35.

> *controllable by SONI and have been thrust upon it by virtue of historical legacy industry arrangements.*
>
> *It was a requirement of the divestment of SONI that "mirrored", identical pension arrangements were put in place by any acquirer; this has been done. The level of contribution reflects these "mirrored" arrangements. The level of contribution sought in the SONI submission is also consistent with the summary draft actuarial valuation carried out on behalf of SONI and provided to the Utility Regulator. For all these reasons it must be recognised that the ongoing cost of the Defined Benefit pension scheme represents an uncontrollable cost.*

40.34 In its 2010-2015 Decision Paper, the Utility Regulator accepted this explanation and determined that the Appellant should be allowed to recover 100 per cent of the ongoing costs of the DB Scheme:[361]

> *The Utility Regulator has decided to allow 100% of ongoing costs for the defined benefit section of the pension scheme.*

40.35 This decision ensured that the Appellant was remunerated in full for covering the ongoing costs of the DB Scheme – all members of which had protected rights inherited from NIE – including the costs of administering the scheme. The policy was consistent with ensuring that the Appellant's costs could be recovered in full in circumstances where it was subject to legal obligations restricting its ability to alter the terms of employees' pension arrangements.

40.36 Consistent with this policy, the Utility Regulator then saw fit to pay for the full costs of the scheme at the 40.3 per cent rate when it approved the Appellant's tariff submissions in 2014 and again in 2015 which included the Appellant's higher DB pension contribution rate pursuant to paragraph 8.1(d) of Annex 1 of the Licence.[362] This covered the costs of the scheme that arose from the point at which the independent actuarial valuation took effect in July 2014 which were over and above the allowances granted for the 2010-2015 period.

40.37 This contrasts markedly with the Utility Regulator's approach for the 2015-2020 price control where it decided not to fund the Appellant for the full contribution rate of 40.3 per cent. If the Utility Regulator had any doubt as to the continuing validity of this approach (which the Appellant submits it cannot have had), it should have had regard to other regulatory practice in circumstances where legal obligations arising from protections put in place at privatisation apply in perpetuity thus restricting the ability of the employer to reduce pension contributions.

40.38 As Punter Southall reports, a largely analogous situation is found with the Civil Aviation Authority's most recent price determination for NATS (RP2).[363] In March 2014, the Government Actuary's Department provided an analysis of pension costs for the CAA in which it identified that the NATS scheme benefits were more generous than those provided by typical UK private sector DB schemes reflecting the *"scheme's public sector origins and protections put in place at*

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[361] 2010-2015 Decision Paper, page 20 **[NOA1/6]**.

[362] Letter from the Utility Regulator to SONI, *"Utility Regulator approval of SSS Tariff for 2014-15"*, 18 August 2015 **[BT1/48]** and letter from the Utility Regulator to SONI, *"Utility Regulator approval of SSS Tariff for 2016/17"*, 31 August 2016 **[BT1/64]**.

[363] Paragraph 6.132-135 of the Punter Southall Report **[JS1/1]**.

privatisation".[364] As a consequence – and in contrast to the Utility Regulator's approach in this case, the CAA determined that it was obliged to ensure that it allowed a level of contribution to be funded by charges sufficient to remunerate NATS' legal commitments over the long term:[365]

> *The CAA accepted that the legal restrictions on the Scheme's amendment power broadly prevented an amendment to the Scheme's rules being made to reduce or stop the future accrual of benefits for the pre-existing members of the scheme. The CAA accepted that this precluded NERL from making changes to the scheme on a scale envisaged by users. The CAA considered that in the absence of changes to the scheme itself, placing any dramatic limitation on contributions allowed in user charges would make it unreasonably difficult for NERL to finance its functions and may impact on the continuing provision of services. It therefore considered that in general it should allow a level of contribution to be funded by charges sufficient to remunerate NERL's legal commitments over the long term.*

40.39 Given the absence of any reasons to justify a departure from its earlier policy and practice, the Utility Regulator ought to have adopted an equivalent approach. Its analysis ought to have been a simple one: recognising the Appellant's legal obligations and limited ability to make any changes to costs of the DB Scheme, the Appellant should have been allowed to fully recover the pensions allowance which was recommended in independent expert advice.

(c) Failure to discharge Financeability Duty

40.40 There is no evidence in the Decision that the Utility Regulator, in determining pensions allowances, had any regard to the Appellant's ability to finance its pension costs. Punter Southall produced an independent assessment of the Utility Regulator's decision and concludes:[366]

> *NIAUR's decision appears to have little or no regard to the actual cost of SONI of providing continued benefit accrual for current active members of the Scheme and indeed the actual cost is not reflected in the rationale given.*

40.41 The Utility Regulator failed in its Financeability Duty by not having regard to or giving appropriate weight to the Appellant's ability to finance its activities. The failure to allow the full amount was a clear error and has led to the Appellant being underfunded by a minimum of £1,489,000 over the Price Control. The impact of the shortfall can be seen by comparing this to the average expected equity returns of between £0.4 million and £1.0 million per annum.

40.42 The Utility Regulator's decision to fund the Appellant at 28 per cent is clearly insufficient to meet the Appellant's legal obligations under the schedule of contributions. Having received no funding for almost 50 per cent of its pension costs, the Appellant's shareholder is exposed to

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364 "Government Actuary's Department: Advice to the Civil Aviation Authority – RP2 Price Control Review for NATS En Route Plc, Analysis of Pension Costs", 14 March 2014.

365 CAA, "*Decision on modifications to NATS (En Route) plc licence in respect of the Oceanic price condition for 2015-2019*", January 2015 (available at http://publicapps.caa.co.uk/docs/33/CAP1254_Decision_Oceanic.pdf) – this is the price control for Oceanic (the monopoly service over the Shamwick/Oceanic control area), which in turn refers to the decision adopted by the CAA for NERL (the monopoly en route service provider in the UK Flight Information Regions).

366 Paragraph 6.31 of the Punter Southall Report, **[JS1/1]**.

the risk of having to fund the remaining contributions out of its own pocket given it is legally obliged to meet the required contribution levels. Punter Southall confirms:[367]

> *SONI has no ability to change the benefits that it provides to members of the Scheme going forward. It is therefore reasonable in my opinion for SONI to expect to be able to recover the cost of providing those benefits in full.*

40.43 The Utility Regulator states that *"a number of options were considered"*[368] in relation to funding the ongoing costs of the DB Scheme but has failed – in any of the consultation documents, in correspondence or in discussions with the Appellant – to provide any further details as to what those options were or why they were dismissed.

40.44 An important line of enquiry the Utility Regulator ought to have pursued when assessing the Appellant's financeability was whether or not the costs of the DB Scheme were capable of increasing during the Price Control Period. However, there is no evidence that the Utility Regulator turned its mind to this issue. This is a significant oversight. In fact, the suggested contribution rate of 40.3 per cent is only the <u>expected</u> cost of providing the pension scheme benefits as at 31st March 2013 based on market conditions at that date and the method and assumptions agreed by the trustees of the scheme with the Appellant after taking independent actuarial advice. The <u>actual</u> cost of providing the benefits to the members of the DB Scheme of the Appellant's pension scheme will depend on a number of factors, including future inflation levels, how long members live and the investment returns earned on the DB Scheme's assets.

40.45 The effects of the Utility Regulator's failure to consider the full financial effects of its decision on pension costs must also be considered in the context of the Appellant's ability to absorb such costs above the allowances granted, i.e. its financial headroom. In the Appellant's case its headroom is limited given its nature as an asset light business, which means it has a significantly smaller balance sheet than (for example) the DNOs assessed by the GAD Reports. The creation of a significant pensions deficit across the Price Control Period would therefore risk significant effects on the Appellant's financial position and its ability to fund its activities. The Utility Regulator's failure to undertake such an assessment of these risks was in breach of its Financeability Duty.

Error 10(b) Pension deficit recovery

40.46 In December 2014, the Utility Regulator published a paper entitled "*Pension Deficit Recovery – A Utility Regulator Position Paper*" (the **Position Paper**) setting out a new approach to pension deficit recovery for regulated energy businesses in Northern Ireland by introducing a "cut-off" date of 31 March 2015. All deficits existing at the cut-off date would be treated as "historic" and deficits after that date would be "incremental". Historic deficits up to the cut-off would be 100 per cent recovered from customers and incremental deficits thereafter would be 100 per cent funded by the licensee. This approach was purported to be a restatement of that set out by the Competition Commission for NIE in its Final Determination on the RP5 price control determination for that business published in March 2014.

[367] Paragraph 6.136 of the Punter Southall Report, **[JS1/1]**.

[368] Paragraph 137 of the Final Determination.

40.47 The Utility Regulator noted that for certain industry participants (but not SONI) existing licence provisions permitted the Utility Regulator to change the current pension deficit recovery principles after notification to the licensee. The Utility Regulator explained that it would develop a set of “Pensions Principles and Regulatory Instructions and Guidance (**RIGS**)” for pension costs based on the Ofgem Pension RIGS methodology applied to distribution network operators in Great Britain requiring companies to report on deficits incurred pre- and post- the cut-off date. To date, no such guidance has been published, in draft or otherwise.

<u>The Utility Regulator’s Decision</u>

40.48 The Utility Regulator recognised that it had no power to unilaterally modify the Appellant’s licence and confirmed it would consult on its pension deficit proposals during the price control review:[369]

> *The SONI licence does not include a similar clause as is included in the Power NI and PPB licences. However, the UR is minded to apply the same principles of deficit recovery to SONI to ensure consistency of treatment. This will be <u>consulted on</u> as part of the Draft Determination for the next SONI price control due to commence in October 2015.* (Emphasis added)

40.49 However, in the Draft Determination the Utility Regulator failed to seek views on whether it was appropriate to adopt a new approach to pension deficit recovery for the Appellant. Instead it confirmed that it would adopt the approach set out in the Position Paper:[370]

> *During December 2014 the Utility Regulator published a Pension Deficit Recovery Position Paper. This paper follows the pension deficit decision made by the Competition Commission’s …final determination on NIE price control in 2014. In respect of all remaining price controlled businesses with pension deficits, of which SONI Ltd is one, the Utility Regulator’s position is the introduction of a “cut-off” date of 31 March 2015. Up to this date a historical pension deficit will be 100% recovered from consumers after which any incremental deficit will be 100% funded by the licensee.*

40.50 The Appellant strongly objected to the Utility Regulator adopting a position which clearly had significant consequences for its financeability absent conducting any form of consultation, as explained in BT1. Despite the Appellant’s submissions, the Utility Regulator confirmed its position in the Final Determination without conducting any further assessment. It sought to justify its general policy decision by commenting that:[371]

> *…for consistency of treatment it is correct to ensure that each price control follows the same core principles. It would be inequitable that NIE had to abide by the decision of the Commission but other regulated businesses continue to recover all deficits, historic and incremental, on a 100 per cent basis from customers. The UR therefore proposes to apply the Commission’s decision to all price controls where the licensee seeks to recover monies from customers to cover the costs of pension deficit.*

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369 Utility Regulator, “*Pension Deficit Recovery – A Utility Regulator Position Paper*”, 22 December 2014 (**Position Paper**), page 6 **[NOA1/10]**.

370 Draft Determination, paragraphs 96-97 **[NOA1/11]**.

371 Position Paper, page 4 **[NOA1/10]**.

40.51 The Utility Regulator did not offer any legal basis as to why the Competition Commission's decision in NIE's previous price control should bind other entities it regulated. There is none. Its approach appeared to be motivated by ease and convenience as opposed to any conviction that it was necessary or appropriate for the Appellant.

40.52 In consequence of this decision, the Utility Regulator proposed to introduce a Licence provision requiring the Appellant to provide it with relevant pension deficit information – splitting the historic and incremental deficit – back-dated from the date of the Final Determination to 31 March 2015. The Utility Regulator explained that the information should be "in line with the information submitted within GB to Ofgem".[372] No guidance was offered as to the form this information should take.

40.53 In response, the Appellant continued to raise strong objections about the Utility Regulator's failure to consult on its proposals, to provide guidance to explain its requirements and to give adequate consideration to the impact of the proposals on its financeability.[373] In addition to the issue of pension deficit recovery, the Appellant continued to dispute the Utility Regulator's approach to setting the ongoing contribution rate.

40.54 Following discussions with the Appellant, the Utility Regulator proposed to consult further in respect of its proposed approach for costs arising in respect of any additional pension deficit occurring from 1 April 2015 and any associated information requirements.[374] The Utility Regulator explained that any further consultation would be limited in scope and would not take into account changes to the contribution rate, noting: [375]

> *We should confirm however that such further consultation will be in respect of the treatment of future pension deficits (and associated provision of information requirements) only.*

40.55 No indication was given as to the timing of the consultation but in at a meeting on 7 June 2016 between SONI and the Utility Regulator, the Utility Regulator confirmed its intention to publish the Decision in advance of any further pensions consultation, thereby locking-in its position on the ongoing contribution rate.[376] The Appellant raised concerns that by severing these issues the Utility Regulator would fail to consider its ability to finance pension costs in the round, in breach of its Financeability Duty. This could mean the Appellant had to appeal two decisions not one.[377]

40.56 Following reassurances from the Utility Regulator, the Appellant proceeded on the basis that all outstanding pensions issues would be resolved prior to the publication of the Decision. It repeatedly urged the Utility Regulator to resolve these issues during the period from June 2016

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372 Final Determination, paragraph 118 **[NOA1/12]**.

373 See SONI response to the Utility Regulator's consultation on the draft Licence Modifications dated 23 March 2016 **[RJM1/2]**.

374 Letter from Utility Regulator to SONI dated 13 May 2016, paragraph 3.5 **[RJM1/3]**

375 Letter from Utility Regulator to SONI dated 13 May 2016, paragraph 3.6 **[RJM1/3]**.

376 Email from the Utility Regulator to SONI dated 10 June 2016 summarising the action points arising from the meeting of 7 June 2016, page 3 **[BT1/61]**.

377 Letter from SONI to Utility Regulator dated 14 June 2016 **[RJM1/4]**.

to March 2017 (including sharing with the Utility Regulator the initial results of the 2016 valuation).[378]

40.57 Ultimately, for reasons unknown to the Appellant, the Utility Regulator decided to issue the Decision but to consult further on the issue as to who should pay for any incremental deficit arising post the 31 March 2015 cut-off date. The Utility Regulator explained that it had adjusted some of the proposed Draft Licence Modifications to give effect to this decision, reinstating the provision to recover pension deficit costs under the Dt term and the removing the requirement to provide pension deficit information. Having received the initial results of the 2016 valuation, the Utility Regulator also indicated it would consider the impact of this valuation in terms of ongoing contributions as part of the further consultation.

40.58 No indication has been given as to when the further consultation will take place although Utility Regulator has shared a draft consultation paper with the Appellant. The draft consultation paper covers ongoing contribution rates (in light of the initial results of the 2016 actuarial valuation); funding of any incremental deficit post 1 April 2015; and the pensions element of the capex TUPE staff referred to in Error 9.

Why the Utility Regulator's decision is wrong

40.59 The Utility Regulator was wrong to try to impose exactly the same approach to pension deficit recovery for the Appellant as it had for NIE. There is no legal requirement that the Utility Regulator shall apply an "equitable" approach to regulating energy businesses in Northern Ireland. Nor is there any merit in the suggestion that to achieve "equity" as amongst regulated businesses in Northern Ireland the same cut-off date should be applied. The Appellant operates a very different business from NIE. An "equitable" outcome would need to take into account these differences and the relative scale of the impact of the decision in terms of financeability.

40.60 The Utility Regulator appears to accept that it failed to consult adequately on the impact of applying this approach to pension deficit recovery for the Appellant prior to issuing the Final Determination, committing in June 2016 to undertake further consultation on its position, as explained in paragraph 61 of BT1. Certainly no other reason is given for proposing to consult again so soon in relation to this matter. The Appellant strongly urged the Utility Regulator to re-consult prior to publishing its final licence modification decision. This was because, as explained further below, a decision that the Appellant should pay for any incremental pension deficit arising past the cut-off date, inevitably has implications for the level of allowances made for the cost of future benefit accrual. The issues are not severable, in particular when It comes to considering the effects of pensions decisions on financeability. Moreover, the Utility Regulator cannot adequately assess whether it has secured the Appellant's financeability over the Price Control when certain elements of the Price Control remain undetermined. Nonetheless, the Utility Regulator decided to delay its consultation until some as yet unspecified date.

40.61 Separating the pensions issues impacts the Appellant's procedural rights. When the Utility Regulator seeks to give effect to any later decision as to who bears the burden of funding any

[378] Barnett Waddingham LLP, "Actuarial valuation as at 31 March 2016: Initial results", 12 September 2016 **[AS1/7]**.

incremental pension deficit recovery by modifying the Licence, then the Appellant has the right to challenge that decision by appealing to the CMA. The Utility Regulator's decision to delay consideration of this issue raises the prospect of the Appellant challenging an adverse decision by way of a second appeal to the CMA. A second appeal on related issues would clearly not be in the interests of efficiency and/or the costs that would be incurred by the Appellant, the CMA or in fact the Utility Regulator, nor could it be said to serve the interests of customers and consumers in Northern Ireland. As explained in BT1, the Appellant made submissions to the Utility Regulator on more than one occasion to this effect, to raise its concerns about a bifurcated process and the effects on its right of appeal, but the Utility Regulator ignored them.

40.62 Such an approach might be understandable in circumstances where, for example, there was significant uncertainty surrounding a particular project, in which case an interim licence modification (re-opener) might be called for. However, in the present circumstances, all matters concerning pension costs should have been answerable within the price control review process. Or – given the Utility Regulator's significant delay in implementing the Price Control and the additional nine months that elapsed between the decision to consult further and the Decision – the overall decision could have been further delayed by a short period of time to allow for the issues to be resolved. This error not only affects the Appellant but any third parties who are materially affected by the decision and have rights to appeal, contrary to the principles of natural justice.

40.63 The Appellant explained to the Utility Regulator on repeated occasions that the decision to sever the issues could have significant consequences for the Appellant's ability to fund any future pension deficit. Punter Southall explains why these issues cannot and should not be considered in isolation:[379]

> *In my opinion, special consideration should be given to the allowance for the cost of future benefit accrual if regulated companies are not able to recover any deficit that arises in the future in respect of future benefit accrual (i.e. if a cut-off date exists). In particular, it does not seem fair or appropriate to allow SONI any less than the expected cost of providing the future benefit accrual that it is legally obliged to provide on the prudent funding basis agreed with the Trustees of the Scheme.*
>
> *The expected cost of future benefit accrual should in my view be assessed using the same actuarial method and assumptions as used to assess the deficit in respect of benefits accrued prior to the cut-off date. If this is not the case and in particular the allowance for the expected cost of future benefit accrual is based on less prudent assumptions than the pre-cut off date deficit, a deficit would be expected to emerge in respect of post cut-off date benefit accrual that SONI would not be able to recover. In effect, SONI would be legally required to provide benefits without sufficient funding to do so.*
>
> *Furthermore, if SONI has no ability to recover its costs in respect of any deficit arising in relation to future benefit accrual after the cut-off date, SONI may reasonably consider it appropriate to take a more cautious approach to the Scheme's funding and investment*

[379] Paragraphs 6.139 – 6.141 of the Punter Southall Report, **[JS1/1]**.

strategy. This would increase the expected cost of future benefit accrual above the level disclosed in the 2013 valuation.

40.64 The Appellant is also concerned about the limited scope of the further consultation insofar as it concerns pension deficit recovery. The Utility Regulator saw fit to calculate the historical deficit up to cut-off date of 31 March 2015 despite never having consulted on whether it was appropriate to impose a cut-off date at all and, if so, what an appropriate date might be for the Appellant.

40.65 On the first point, the Appellant suggests that there are good reasons why it is not appropriate to impose a cut-off date for pension deficit recovery. Punter Southall explains:[380]

SONI has very little control over the cost of future benefit accrual or over the emergence of a deficit in the Scheme relating to post cut-off date benefit accrual. I therefore consider it appropriate that SONI be permitted to recover all contributions it makes towards any deficit arising in the Scheme.

SONI would have greater ability to reduce the risk of a deficit emerging in respect of post cut-off date benefit accrual if NIAUR were to grant them a higher allowance for the cost of future benefit accrual. This would allow SONI to adopt a lower risk investment strategy. However, doing so would increase the expected cost of providing future benefit accrual.

40.66 Specifically, the Utility Regulator should have regard to the specific characteristics of the DB Scheme including its size. Punter Southall compares the Utility Regulator's approach against that of other regulators and finds it disproportionate:[381]

One could argue that it would not be the actions of a proportional regulator to force SONI to incur the extra administration costs associated with operating a cut-off date. One could also make a case that it is not targeted to apply the same "one size fits all" approach to all regulated companies, regardless of their specific circumstances. SONI cannot control deficits in respect of future benefit accrual unless it is allowed sufficient funding for future benefit accrual costs to invest all contributions in gilts and provide a buffer against adverse mortality experience. Even then, a residual risk of a deficit arising would remain.

Other comparable regulators have operated differently to NIAUR in these respects. For example, Ofgem consulted with regulated companies before introducing a cut-off date and the Competition Commission took account of the exceptional circumstances at Bristol Water. In my opinion it would be appropriate for NIAUR to have regard to the processes followed by these other regulators and the decisions they reached when it consults further on both the ongoing contributions and any additional pension deficit occurring from 1 April 2015.

40.67 If having conducted a thorough assessment the Utility Regulator does conclude that it is necessary to impose a cut-off date, it must also give proper consideration as to at what an <u>appropriate</u> cut-off date is. The Appellant can see no reason why the answer should be to apply

[380] Paragraphs 7.56 – 7.57 of the Punter Southall Report, **[JS1/1]**.

[381] Paragraphs 7.59 – 7.60of the Punter Southall Report, **[JS1/1]**.

the same date as for NIE not least because of the inordinate administrative burden of imposing a retrospective date and how this would disproportionately apply to its business.

40.68 In practical terms, Punter Southall explains that introducing a cut-off date would require the Appellant to effectively split the DB Scheme in two for the Utility Regulator's purposes, and run it as two separate notional sub-funds (tracking any deficit pre- and post- the cut-off date). This would incur additional administration fees. The level of contributions awarded for future service benefits after the cut-off date would go into the second sub-fund meaning that the size of any deficit arising in the second sub-fund is intrinsically linked to the allowance for future service benefits. Punter Southall note in this regard:[382]

> *I consider the additional compliance burden that the operation of the cut-off date would have on SONI to be disproportionate to the benefit to consumers and note the practical difficulties (and additional cost burden) associated with implementing the cut-off date retrospectively.*

40.69 Moreover, as Punter Southall explains, the Utility Regulator has erred in its calculations of how the historical deficit up to the cut-off date of 31 March 2015 should be funded. The Utility Regulator's approach – of taking the total deficit and dividing it by ten – does not provide sufficient funding to meet the historical deficit. It fails to take into account the time value of money (NPV).[383] As discussed in Part D of BT1, this error was pointed out by the Appellant to the Utility Regulator but the Utility Regulator failed to correct it. This is yet further evidence that the Utility Regulator failed to conduct a thorough financeability assessment, or indeed to exhibit an understanding of the manner in which pensions and pension deficits affect the financeability of the Appellant.

41 Summary of relief sought

41.1 This Section of Part IV of the Notice summarises the relief sought in respect of Error 10. The specific relief sought is set out in Part V of the Notice.

41.2 In summary, the Appellant requests that the CMA amend Annex 1 of the Licence so as to include provision for the full actuarial costs of the ongoing employer pension contributions. In addition, there must be provision for the Appellant to recover any updated costs pursuant to any new actuarial reports regarding both the ongoing contributions and the DB Scheme deficit finalised during the Price Control Period.

41.3 The Appellant also requests that the CMA direct the Utility Regulator that, to the extent it determines it is necessary to apply a cut-off date, having first consulted thoroughly, it should not do so retrospectively.

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382 Paragraph 7.58 of the Punter Southall Report, **[JS1/1]**.

383 Paragraph 7.15 of the Punter Southall Report, **[JS1/1]**.

Error 11 - Failure to provide adequate IS capital expenditure allowances

42 Overview

42.1 Error 11 concerns the Utility Regulator's failure to provide adequate information systems capital expenditure (**IS capex**) allowances.

42.2 Information systems play a critical role in enabling the Appellant to efficiently operate the Northern Ireland electricity transmission system. Not only will these information systems require ongoing maintenance during the Price Control Period but new changes and enhancements must also be made if the Appellant is to deliver the greater efficiencies and innovation required by Government, by system users and by consumers.

42.3 The Appellant requests that the CMA read by way of introduction to this topic:

(a) BT1, which explains why the Appellant's IS capex submissions were justified; and

(b) AS1, which explains the adverse impact on the Appellant's financeability created by the shortfall in funding.

42.4 The Appellant submits that the Utility Regulator was wrong to set the IS capex allowances at £6.622 million over the Price Control – nearly £2.3 million less than that submitted by the Appellant.[384] The Appellant has identified two specific errors:[385]

(a) exclusion of DS3/Smart Grids – the Utility Regulator failed to allow the £1.333 million required to fund investment in the DS3/Smart Grids project, one of eight key IS system areas (each, a **Project** and together, the **Projects**) designed to deliver necessary changes and enhancements to systems operations, having wrongly determined that this workstream should be excluded from the price control as a SEM Matter; and

(b) incorrect adjustment for inflation - the Utility Regulator made an incorrect adjustment for inflation (rebasing the IS capex submission to 2014 prices on the erroneous assumption that 2015 prices had been provided) reducing the IS capex allowance by a further £291,000.

42.5 This error is exacerbated by the Utility Regulator's failure to include sufficiently detailed reasons or justification for its approach in the Decision, the Final Determination or elsewhere, or to provide any meaningful response to the Appellant's submissions.

42.6 Accordingly the Utility Regulator's Decision in setting the IS capex allowances was wrong by reference to the statutory grounds detailed in Part III of this Notice, as summarised below:

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[384] The Appellant's requirements are premised generally on the delivery of integrated solutions in order to maximise cost efficiencies and consumer benefits. Where appropriate, costs are allocated between the two TSOs in Northern Ireland and the Republic of Ireland in line with the EirGrid Group cost allocation policy that was submitted to the Utility Regulator as part of the Business Plan.

[385] The remaining shortfall is accounted for by the Utility Regulator's decision regarding an efficiency target.

(a) The Utility Regulator failed under sections 14D(4)(a) to properly have regard to its duties under Article 12(2)(b) of the Energy Order to have regard to the need to secure that licence holders are able to finance their regulated activities, through excluding DS3/Smart Grids and making an incorrect adjustment for inflation.

(b) The Utility Regulator failed under section 14D(4)(a) to properly have regard to and duties under Article 12(5)(a) of the Energy Order to promote the efficient use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity, as regards the failure to fund DS3/Smart Grids.

(c) The Utility Regulator erred in fact through excluding DS3/Smart Grids and making an incorrect adjustment for inflation (Article 14D(4)(c)).

(d) The Utility Regulator erred in law by failing to properly consider the case for funding the investment in the DS3/Smart Grids Project and by failing to take account of the Appellant's pleas to correct the incorrect adjustment for inflation contrary to good regulatory practice (Article 14D(4)(e)).

42.7 The Appellant requests the relief summarised below and set out in Part V of the Notice.

43 Background

43.1 The management of information, and therefore the use of information systems (**IS**), is critically important to the Appellant in efficiently operating the Northern Ireland transmission system in a safe, secure and reliable manner, ensuring all reasonable demands for electricity are met. The Appellant is required to maintain and optimise its existing IS systems during the Price Control Period, while also continuing to develop IS system changes and enhancements to meet the evolving requirements of the Government's policy objectives.

43.2 The IS capex allowance sets the level of investment the Appellant is able to make in IS systems during the Price Control Period. Shortfalls in investment can therefore be expected to impact the efficiency of transmission system operations and hinder the realisation of consumer benefits from IS initiatives.

43.3 In the Business Plan the Appellant's overall capex requirements amounted to a total planned investment of £9.416 million of which the IS capex portion amounted to £8.927 million.[386] The submissions were made in 2014 prices in accordance with the Utility Regulator's Business Plan requirements. The Appellant provided a detailed paper on "Information System Drivers" (**Paper 10**) to supplement the IS capex submission.[387] In Paper 10, the Appellant identified eight key Projects for system maintenance, changes and enhancements and provided a detailed

386 Business Plan, Paper 5, "*SONI Business Plan Information Requirement Schedules*", tab 3.9, rows 11-19, **tab 5 of [BT1/31]**. See also BT1 for an explanation of the process the Appellant undertook in estimating the required expenditure for each Project.

387 Business Plan, Paper 10, "*SONI Revenue Review 2015-2020, Paper 10 - Information System Drivers*", **tab 10 of [BT1/31]**.

explanation of the key components and associated investment required to deliver the relevant outputs over the Price Control Period.[388]

43.4 Critically, the Appellant explained in Paper 10 that its submission did not include the costs of any IS capex projects associated with “DS3 System Services”. DS3 System Services is one of eleven different workstreams making up the overall DS3 Programme. This workstream was initiated as a means to identify new ancillary service products that are needed to complement the shift towards a power system with high levels of non-synchronous generation from renewables. Prior to the Price Control review, the implementation of the DS3 System Services workstream had been deemed a “SEM matter”,[389] meaning any decisions in relation to this workstream are subject to determination by the SEM Committee (and therefore excluded from the Price Control). All decisions in relation to the other ten workstreams (i.e. non-System Services) remain exclusively within the domain of the Utility Regulator (in respect of Northern Ireland).

43.5 One of the eight Projects covered by Paper 10 was titled “DS3/Smart Grids”[390]. This covered two separate components – DS3 Non-System Services work and Smart Grids work – but had been bundled together owing to certain commonalities between them. The expected expenditure for the combined DS3/Smart Grids Project was £1.333 million across the Period, allocated as follows:[391]

(a) DS3 Performance Monitoring Data – £417,000;

(b) DS3 tools – £625,000; and

(c) Smart Grids[392] – £292,000.

43.6 Having already set out that the Business Plan did not cover any required IS capex investment for DS3 System Services, the Appellant did not see the need to explicitly label the DS3 work within the DS3/Smart Grids Project as “Non-System Services”. The overall DS3 programme is described by the Utility Regulator as a key output of the Price Control and, as explained in paragraph 58 of RJM1 is expected to lead to overall cost saving benefits for consumers across the island of Ireland of approximately €177 million per annum.

388 Business Plan, Paper 10, “*SONI Revenue Review 2015-2020 Paper 10 - Information System Drivers*”, page 7, **tab 10 of [BT1/31]**.

389 See BT1.

390 Business Plan, Paper 10, “*SONI Revenue Review 2015-2020 Paper 10 - Information System Drivers*”, section 3.7, **tab 10 of [BT1/31]**.

391 Business Plan, Paper 10, “*SONI Revenue Review 2015-2020 Paper 10 - Information System Drivers*”, pages 16-17, **tab 10 of [BT1/31]**.

392 Smart Grids involves managing data securely around the Smart Grid infrastructure, including the secure collection, delivery and storage of the high volume of data produced in a smart grid (for example, installing secure storage structures, bandwidth increase work, and industry standard encryptions for bid data in transit) and meeting governance measures concerning security policies for Smart Grids, including new procedures and standards as well as specific policies for managing data and protecting against cyber security.

44 Errors

44.1 The Utility Regulator was wrong not to provide the Appellant with adequate IS capex allowances. There are two elements to this error: first, the decision to exclude DS3/Smart Grids and second, the incorrect adjustment for inflation.

Error 11 (a) Exclusion of DS3/Smart Grids

44.2 In the Draft Determination, the Utility Regulator proposed to exclude all of the Appellant's estimated expenditure associated with "DS3/Smart Grids" from the IS capex proposal, explaining:[393]

> *Further work is needed within this price control process in terms of how this price control will interact with the DS3 workstream.*

44.3 In reaching this provisional decision, the Utility Regulator made several references to "DS3" without specifying which workstream it was referring to. It failed to draw a distinction between the investment associated with the DS3/Smart Grids Project on the one hand and investment in the DS3 System Services workstream on the other hand and tended to refer to "DS3" as a single programme which was excluded from the Price Control:[394]

> *DS3 is a specific consideration of the SEM Committee separate from the price control. The Utility Regulator proposes to not include a provision for this allowance within the Draft Determination.*

44.4 In its written response to the Draft Determination, the Appellant explained that the expected investment expenditure associated with DS3/Smart Grids was <u>not</u> associated with the DS3 System Services workstream. The Appellant also stressed the importance of the DS3/Smart Grids Project in advancing the eventual implementation of the DS3 System Service workstream:[395]

> *…It should be stressed that the full implementation of DS3 requires all the workstreams to be implemented in order to ensure that expected generation portfolio can be accommodated on the system, in accordance with SONI's duties under the European and National legislation, its licence and the Grid Code. IS capex costs for DS3 System Services were not included in the 2015-20 submission however those associated with the other workstreams including Performance Monitoring, new Control Centres Tools etc. were included as these are not part of the System Service workstream. However, if the cost reduction is implemented there are likely to be delays in facilitating the implementation of the DS3 System Service workstream governed by the SEM Committee.*

44.5 Further meetings were held between the Utility Regulator and the Appellant during May[396] and June[397] 2015 where the Appellant yet again sought to correct the error. Upon receipt of the draft

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393 Draft Determination, paragraph 166 **[NOA1/11]**.

394 Draft Determination, page 31, paragraph 140 **[NOA1/11]**. In the context of this quote, the Utility Regulator had referred to "professional fees" for DS3 but the decision not to include provision for this allowance extended to all DS3 cost lines.

395 SONI Response Appendix to: NIAUR Draft Determination, paragraph 2.2.5 and section 5.3 **[BT1/40B]**.

396 See BT1 and SONI presentation for discussion with Utility Regulator 6 May 2015 **[BT1/38]**.

Final Determination in December, the Appellant yet again advised the Utility Regulator of the error.[398] These submissions were also ignored.

The Utility Regulator's Decision

44.6 In the Final Determination, the Utility Regulator confirmed that it had deferred making an explicit provision for the entire £1.333 million DS3/Smart Grids Project in the Appellant's IS capex programme because in its view it believed it was outside of the scope of the price control: [399]

> *As with the Draft Determination costs explicitly relating to DS3 are outside of the scope of this price control and therefore an explicit provision for DS3 within CAPEX has been deferred and will be considered afresh within the cost recovery framework to be established by the relevant authorities.*

44.7 The Utility Regulator referred to work undertaken by its consultant Gemserv. Gemserv stated in its report on its review of the Appellant's IT strategy and costs:[400]

> *If, as implied in the SONI submission, that they will need to make a separate IT submission for this work, (presumably under a Dt term) it is suggested that no allowance is made at this junction, only to recognise that it is not a disallowance but a deferred cost approval awaiting further clarification.*

44.8 Gemserv misunderstood that only DS3 System Services costs and not other DS3 costs had been excluded from the Business Plan. No justification was offered as to why the Smart Grids component was also excluded from the Price Control allowances.

44.9 In the Decision Paper, the Utility Regulator continued to demonstrate confusion as to which elements of the DS3 programme fell to be determined by the SEM Committee and which elements fell within the Price Control:[401]

> *With regard to costs relating to the non-system services elements of the wider DS3 programme, SONI would have to demonstrate that the "non-system services" element of DS3 is part of the DS3 System Services programme.*

44.10 The Appellant cannot reconcile this statement. It makes no sense.

44.11 The Utility Regulator suggested that the Appellant might be able to claim for the DS3 costs as part of a wider DS3 Dt claim, although it would need to demonstrate that the costs were not recoverable under the IS capex expenditure allowed within the Price Control - even though no allowance was actually provided.[402]

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397 See paragraph 47(c) of BT1.

398 SONI Response: Factual Review, 15 December 2015, at page 10 **[BT1/55]**.

399 Final Determination, Paragraph 218 **[NOA1/12]**.

400 Gemserv Report, pages 12, 17 and 18, section 5.7 **[NOA1/16]**.

401 Decision Paper, paragraph 65 **[NOA1/18]**.

402 Decision Paper, paragraph 65 **[NOA1/18]**.

Why the Utility Regulator's Decision is wrong

44.12 The Appellant's planned expenditure in respect of the "DS3/Smart Grids" Project is not part of the DS3 System Services workstream. It is not a SEM matter and did not fall to be separately considered by the SEM Committee. On the contrary, the DS3 work included within the DS3/Smart Grids Project represents a small but vital supporting part of the wider DS3 Programme. It falls entirely within the Utility Regulator's remit, and should – along with Smart Grids – have been assessed and an allowance provided for on an *ex ante* basis by the Utility Regulator in the same manner as the other seven IS-capex Projects.

44.13 The Utility Regulator's mistake may have arisen due to a misunderstanding created by its consultant Gemserv that the DS3/Smart Grid costs would be subject to a separate submission. This was not correct. The Appellant had not implied that it needed to make a separate IT submission for any of the components included in its submission. Instead, the Appellant had identified that it was excluding investment associated with DS3 System Services from its submission because this workstream was excluded from the Price Control, as a SEM Matter.[403] The only DS3 investment included in the Business Plan related to non-System Services. Nonetheless the Utility Regulator appeared to rely on Gemserv's incorrect statement as a justification for not making any *ex ante* allowance for the DS3/Smart Grids Project.

44.14 Neither the Utility Regulator, nor Gemserv, sought to query or confirm the position as part of the price control review. Each had several opportunities to do so, as part of the formal queries sent by the Utility Regulator to the Appellant following submission of the Business Plan and during two meetings (between all three parties) held in February 2015 to discuss the Appellant's submission, as explained in BT1.[404]

44.15 Given the Utility Regulator itself acknowledged the delivery of the wider DS3 Programme as one of the "key outputs" of the price control,[405] it was wholly inappropriate and unreasonable for the Utility Regulator to fail to make any provision for investment in the DS3/Smart Grid Project. All the necessary requirements for the works were included in the Business Plan and these works are critical to the delivery of the wider DS3 programme.

44.16 Indeed, it is generally acknowledged that, assuming the efficient and timely delivery of the total DS3 investment, customers will benefit by many multiples of the required investment – not only in terms of meeting renewable targets (and avoiding potential penalties from failing to do so) but from maximising the outputs of renewable generation.

44.17 The failure to distinguish between DS3 System Services costs and costs pertaining to other DS3 workstreams is particularly egregious given that the Utility Regulator is one of the two regulators which together form the SEM Committee, indeed it is in fact the Utility Regulator's SEM Committee itself which is responsible for designating matters as SEM Matters.[406] The Utility Regulator must have been aware that only investment relating to the DS3 System

403 Paper 10: Information Systems Drivers, page 27, final paragraph, **tab 10 of [BT1/31]**.

404 Meetings of February 5th and 12th. As explained in Part D of BT1, no formal minutes of the meeting were exchanged however follow-up queries are on record and demonstrate no specific query being raised in relation to the DS3/Smart Grids expected expenditure.

405 Final Determination, Executive Summary, pages 3-4 **[NOA1/12]**.

406 Pursuant to Article 6(3) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007.

Services workstream, and not broader expenditure associated with DS3, were deemed to be SEM Matters within the meaning ascribed to that term. Nevertheless there are a number of unclear references in the Final Determination to which authority was responsible for "DS3" costs.

44.18 The Appellant asserts that the Utility Regulator is the relevant authority for DS3 non-System Services investment costs, not the SEM Committee (which is the relevant authority for DS3 System Services) or any other body. In fact the Utility Regulator recognises elsewhere in the Final Determination that "*elements of DS3 are a specific consideration of the SEM Committee and separate from the price control*".[407] It is not clear why the Utility Regulator failed to make an assessment in relation to those elements of DS3 in respect of which it had jurisdiction to do so.

44.19 By way of contrast, the CER in its decision paper on the EirGrid TSO price control for 2016-2020 made full provision for the EirGrid TSO's portion of the revenue requirements associated with DS3/Smart Grids.[408] Clearly it would not have been open for the CER to do so had the matter been deemed to be a SEM Matter, and therefore within the exclusive jurisdiction of (and for determination) by the SEM Committee.

44.20 As a result of the Utility Regulator's decision, however, the Appellant must:

(a) absorb the costs of delivery of the "DS3/Smart Grids" Project itself, i.e. £1.333 million, with no clear mechanism for full cost recovery. This has clear consequences for the Appellant's financeability, as explained in AS1; or

(b) suspend progress on implementation of the DS3/Smart Grids Project. Clearly, it is not within the interests of consumers and will in turn impair the Appellant's ability to deliver efficiencies in the use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity.

44.21 However, the Utility Regulator's suggestion in its letter of 31 March 2017 that in certain circumstances the Appellant may be permitted to claim DS3 "Non-System Services" expenditure via the Dt mechanism *"as part of the DS3 Dt request"*[409] does not provide sufficient comfort that such costs will be recovered as explained in Part D of BT1.

44.22 At no point did the Utility Regulator clarify that it intended all DS3 related costs to be subject to recovery via the uncertainty mechanism, nor did it provide any reasonable justification for doing so. In addition, it is a wholly inappropriate use of the Dt mechanism to facilitate recovery of costs which were anticipated and quantifiable at the time of the Business Plan.

44.23 It is unclear how the decision to refer to provide an ex-ante allowance for the Appellant to invest in the "DS3/Smart Grid" Project was considered as part of the Utility Regulator's financeability assessment. The failure to provide an allowance for £1.333 million must be assessed in the context of average equity returns for the period which are expected to be between £0.4 million

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407 Final Determination, paragraph 155 **[NOA1/12]**.

408 CER, Decision on TSO and TAO Transmission Revenue for 2016 to 2020, Decision Paper, 23 December 2015, page 73 (https://www.cer.ie/docs/001043/CER15296%20Decision%20on%20TSO%20and%20TAO%20Transmission%20Revenue%20for%202016%20to%202020%20(1).pdf).

409 Decision Paper, paragraph 65 **[NOA1/18]**.

and £1.0 million per annum, depending on the timing of the investments undertaken. This means that the Appellant itself has limited ability to absorb this cost without certainty as to how the investment will be recovered.

Error 11(b) Incorrect adjustment for inflation

44.24 The Utility Regulator's Business Plan template required the Appellant to provide its Business Plan submission in 2014 prices. The Appellant duly provided the information required, including of IS capex claims.

44.25 In February 2015 the Utility Regulator wrote to the Appellant stating that it had assumed that a 2015 price basis had been utilised for both opex and capex. The Utility Regulator sought to confirm its assumption as follows:[410]

> *I've assumed the price base is April 2015 for both opex and capex. This is based upon Paper 5 tab 3.12 (RAB excluding building) cell N1.*

44.26 The Appellant responded swiftly to advise that this was not correct, and that the 2014/2015 figures were in fact based on 2014 prices.[411] The Appellant received no further communication on this question from the Utility Regulator and therefore assumed its explanation was understood and that the Utility Regulator had corrected its erroneous assumption.

44.27 In the Draft Determination, the Utility Regulator stated that it had "adjusted" the Appellant's capex submission into 2014/15 prices, stating:[412]

> *The Utility Regulator has adjusted SONI's submission from April 2015 to April 2014 prices for consistency with the overall price base for this price control paper.*

44.28 In the Appellant's formal response it again advised the Utility Regulator that its submission was already made on the basis of 2014 prices and that there was no need to further adjust them.[413] The Appellant assumed this error would be corrected.

44.29 As the process continued it became clear that the Utility Regulator had omitted to correct the error so the Appellant repeatedly sought to clarify the issue in November 2015[414] and December 2015.[415]

The Utility Regulator's Decision

44.30 In the Final Determination, the Utility Regulator continued to refer to the need to "adjust" the submission to 2014 prices: [416]

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410 Email "Quick query re price base" from Karen Shiels (NIAUR) to Tanya Gill (SONI) 25 February 2015 **[BT1/35]**.

411 Email from Regulation SONI to Karen Shiels (NIAUR) dated 27 February 2015 **[BT1/36]**.

412 See Draft Determination, paragraph 293 **[NOA1/11]**.

413 SONI Response to Draft Determination 18.05.2016 Appendix to: the Utility Regulator Draft Determination, paragraph 2.5 **[BT1/40]**.

414 Email from SONI to Utility Regulator dated 30 November 2015 including specifically stating "*The 'additions' included within the (RAB) tabs were not uplifted to the 2015 RPI index*" **[BT1/51]**.

415 Factual Review response to the Draft Final Determination dated 11 December 2015, specifically advising that the statement as to the basis for the SONI submission was factually incorrect, at page 9 **[BT1/54]**.

As stated in the Draft Determination SONI presented their Regulatory Asset Base (RAB) which included capex additions in 2014-15 prices. The Utility Regulator revised SONI's RAB and capex additions to April 2014 prices in order to remain consistent throughout the paper.

44.31 The Utility Regulator acknowledged that the Appellant disputed the fact that it had originally presented its submissions in 2015 prices. The Utility Regulator appeared to justify its continued failure to correct its position on the basis that the effect of the error was inconsequential, stating:[417]

…*the allowance provided is adequate for this price control*.

44.32 In fact, the effect of this adjustment was that the capex allowance (which already excluded provision for the "DS3/Smart Grids" Project) was reduced by an additional £291,000. This was prior to any assessment of efficiency (which resulted in a further reduction of £700,000 from the allowance).

Why the Utility Regulator's Decision is wrong

44.33 The Utility Regulator was wrong to assume that the Appellant's capex submission of October 2014 had been made in 2015 prices. This led it to incorrectly adjust the submission by reducing it for the inflationary effect between 2014 and 2015 prices. The Utility Regulator had no justifiable basis to revise the expected capex price base when the figures submitted met its own original specifications (i.e. were in 2014 prices).

44.34 The error was therefore a straightforward error of fact. This could have easily been corrected but was not. Given the Appellant identified the error in February 2015, the Utility Regulator had ample time to make the necessary correction. Indeed, the Appellant made repeated attempts to engage the Utility Regulator on this issue but all attempts were ignored. The Utility Regulator continually failed to respond to the Appellant's submissions, contrary to good regulatory practice, and persisted in incorrectly characterising the issue as a submission error on the Appellant's part.

44.35 The Utility Regulator's finding in the Final Determination that nevertheless "*the allowance provided is adequate for this price control*" suggests that it was aware it had made an error but failed to rectify it because it considered it to have an inconsequential effect. In fact, combined with the Utility Regulator's error to fund the "DS3/Smart Grids" Project, the adjustment error exacerbates the impact of the Utility Regulator's failure to set an adequate capex allowance on the Appellant's financeability and – as an additional allowance error to those already outlined in this Notice – has a material adverse impact on the Appellant's ability to deliver IS system requirements for the benefit of systems users and consumers, as explained further in AS1. There is no further assessment of the impact of the Utility Regulator's errors with respect to the capex allowance within the Final Determination, suggesting that it did not include these in a full and proper assessment of the Appellant's financeability.

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[416] Final Determination, paragraph 198 **[NOA1/12]**.

[417] Final Determination, paragraph 226 **[NOA1/12]**.

45 Summary of relief sought

45.1 This Section of Part IV of the Notice summarises the relief sought in respect of Error 11. The specific relief sought is set out in Part V.

45.2 In summary, the Appellant requests that the CMA amend Annex 1 of the Licence so as to include provision for the full forecast expenditure to be incurred in delivering the DS3/Smart Grids project and make any associated amendments and reinstate the £291,000 cost expected to be incurred in delivering the outputs of the full IS capex programme.

PART V

RELIEF

46 Summary of specific relief sought

46.1 The Appellant requests that the CMA remedy the errors summarised in Part IV of this Notice in the following manner:

(a) in the first instance, by quashing the Decision and substituting its own decision in correction of the errors which secures the Appellant's financeability by giving effect to an appropriate price control design framework for the Appellant and addressing the errors in respect of the inadequate allowances and the inadequate approach to uncertainty; or

(b) in the alternative, by quashing those aspects of the Decision it finds in error and substituting its own decision to the extent necessary to remedy each error found as identified in the Notice; and

(c) by awarding the Appellant its costs in respect of bringing this appeal.

46.2 The order in which the Appellant addresses the specific remedies sought in respect of each Ground is as follows:

(a) Ground 3 – the Inadequate Allowances Ground;

(b) Ground 2 – the Revenue Uncertainty Ground; and

(c) Ground 1 – the Financeability Methodology Ground.

46.3 The reason for this order, despite the numbering of the Grounds, is that the proposed remedy in respect of the Financeability Methodology Ground takes into account and assumes resolution of the other Grounds. This is because, as explained in Part I, Section 5, it cannot be assumed that the correction of the errors under one of the grounds will secure the financeability of the Appellant. For example, remedies that address the errors identified in the Inadequate Allowances Ground will not cure the financeability problems caused by the Financeability Methodology Ground or the Revenue Uncertainty Ground and, equally, corrections of the errors under the Revenue Uncertainty Ground cannot by themselves cure the lack of sufficient allowances for known costs the Appellant was legally obliged to incur.

46.4 The CMA's assessment of whether the Appellant's business is financeable under the remedies chosen should recognise that "financeability" is wider than measuring against metrics - the traditional consideration of financeability by regulators for asset heavy utilities. It should also assess the effects of the treatment of significant costs subject to uncertainties and the ability of the Decision to provide sufficient certainty regarding treatments or risk for lenders and investors to be willing to finance the delivery of expected outputs in the interests of consumers.

(a) Relief sought in respect of the Inadequate Allowances Ground

46.5 The Appellant is seeking relief in respect of a number of errors regarding specific allowances set by the Utility Regulator in the proposed price control arrangements. The non-provision of these allowances, over and above stretched efficiency targets, which are necessary for the

Appellant to fulfil its functions and licence obligations, contributes to the absence of the Appellant's financeability.

(i) Error 9: Relief sought in respect of the Utility Regulator's failure to provide adequate payroll allowances for network planning staff

46.6 The specific relief sought by the Appellant for the opex and capex staff is set out separately below, reflecting the different treatment of each in the Decision.

(A) Relief sought in respect of the costs of the three opex staff protected by TUPE

46.7 The Appellant has been materially underfunded for the costs of three opex staff who transferred from NIE under TUPE legislation. Contrary to assurances provided by the Utility Regulator upon transfer of these employees, the same benchmarked payroll allowance was provided for these employees as in respect of all other (non-network planning) opex staff.

46.8 The Appellant requests that the CMA quash the Utility Regulator's decision to allow the Appellant to recover only a proportion of the actual payroll costs of the three employees, and substitute its own decision by modifying the Licence to provide for full *ex ante* remuneration of these actual payroll costs, as proposed below.

Requested remedy: The CMA is requested to make the following amendment to paragraph 2.2(b)(vi) (Table A) of Annex 1 of the TSO Licence:

Amend the "Payroll" allowance to include an additional allowance of £[redacted].

(B) Relief sought in respect of the costs of the eight remaining capex staff protected by TUPE

46.9 The Appellant has been materially underfunded for the costs of eight capex staff, who also transferred from NIE under TUPE legislation, but in respect of whom no payroll allowance is included in the Appellant's opex headcount or payroll allowance. This is due to the Utility Regulator's decision to provide for recovery of these costs as part of the process of cost recovery for works carried out on PCNPs. There is no further specificity concerning the basis of cost recovery.

46.10 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence to provide an additional *ex ante* Bt allowance which includes the full remuneration for these actual payroll costs, as proposed below. Where these staff costs are subsequently included in the capitalised costs of PCNPs – whether via the SSS tariff (Dt submission) or TUoS tariff (sold onto NIE or to other parties via applicable arrangements) – the equivalent would be adjusted for and returned to consumers via the K-factor mechanism.

Requested remedy: The CMA is requested to make the following amendments to Annex 1 of the TSO Licence:

(i) amend the "Payroll" allowance in Table A at paragraph 2.2(b)(vi) to include an additional line item, "Capex Payroll", and allowance of £[redacted] per annum; and

(ii) amend K_{TSOt} in paragraph 2.2(f) by adding an additional component to the F_{TSOt-2} formula, as follows:

minus

(D) *that part (if any) of the efficiently incurred costs of any Transmission Network Pre-Construction Project, which proceeded to construction and for which full payment has been received, already provided for within Table A at paragraph 2.2 (b)(vi).*[418]

(ii) Error 10: Relief sought in respect of the Utility Regulator's failure to provide adequate pensions allowances

(A) Relief sought in respect of ongoing contributions to the DB Scheme

46.11 The Appellant has been materially underfunded for the employer pension contribution costs it will incur for its active members, of the DB Scheme, all of whom hold 'Protected Persons' status, until at least 2020.

46.12 The expected DB pension contribution costs were included in the Appellant's Business Plan Submission at £770,000 per annum based on actual salary costs and on the assumption that all staff remained in service.[419] Based on the Utility Regulator's Financial Model and the Final Licence Modifications, the Appellant has been allowed only £400,000 per annum until 2020. The Appellant has since asked its actuary to profile the employer contributions requirements, incorporating actuarial assumptions on retirements.[420] This leaves a total funding gap for ongoing employer contributions over the Price Control Period of £1,489,000.

46.13 Given the timing of publication of the Licence Modifications, the results of the 2016 valuation will be finalised during the course of the Appeal. As a consequence, and to reduce the administrative burden for both the Utility Regulator and the Appellant in re-setting the payroll allowances twice, the Appellant requests that the CMA take the forthcoming 2016 valuation into account when remedying the errors. This means applying the 2016 contribution rate from 2016/17 onwards.

46.14 The suggested remedy in respect of the ongoing contributions to the DB Scheme has three elements. First, a new definition should be inserted in reference to the Appellant's DB Scheme costs (to align with the most recent actuarial valuation), and such costs should be transferred from the D_{TSOt} term to the A_{TSOt} component as effectively "uncontrollable" costs. Secondly, the "Payroll" allowance in the TSO Licence should be amended so that it provides the full *ex ante* remuneration of the Appellant's DB Scheme contribution costs, based on the recommended rate included in the most recent (2013) actuarial valuation as adjusted to incorporate assumed retirees rather than constant staff numbers, as per the following table:

418 Where projects do not proceed to construction, the Appellant would seek recovery of all reasonably and efficiently incurred costs under the Dt mechanism, with the exception of any provided under B_{TSOt-2}, as set out in Table A under Payroll.

419 Of the 31 DB members active in 2015, a total of 6 staff could exercise their right to retire within the term of the 2015-20 Price Control. There was a provision in the legacy arrangements for staff to elect to retire at age 60, however they are also entitled to work post age 60. Hence the expected costs remained constant over the 5 years.

420 These assumptions are in line with those expected to be made as part of the finalised 2016 valuation.

	Tariff Year					
Defined Benefit Pension Scheme Employer Contributions	**2015/ 2016**	**2016/ 2017**	**2017/ 2018**	**2018/ 2019**	**2019/ 2020**	**Total**
Actuary Recommended £	868,000	716,000	661,000	647,000	597,000	3,489,000
Utility Regulator Allowance £	400,000	400,000	400,000	400,000	400,000	2,000,000
Delta £	-468,000	-316,000	-261,000	-247,000	-197,000	-1,489,000

46.15 Finally, where these costs are included in the capitalised costs of PCNPs – whether via the SSS tariff (Dt submission) or TUoS tariff (sold onto NIE or to other parties via applicable arrangements) – the equivalent would be adjusted for and returned to consumers via the K-factor mechanism.

46.16 The Appellant therefore requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below.

Requested remedy: The CMA is requested to make the following amendments to Annex 1 of the Licence:

(i) *add a new definition entitled "Pension Scheme Costs", to mean both the employer contributions to the Licensee's pension scheme and the cost of pension deficit repair, as recommended by the Licensee's actuaries in the Licensee's most recently obtained actuarial valuation.*

(ii) *delete paragraph 8.1(d) and add a new cost category to the At_{sot} component in paragraph 2.2(a) as follows:*

> *the Pension Scheme Costs (in Relevant Year t) of the Transmission System Operator Business to the extent not recovered under any other provision of this Licence*;

(iii) *amend the "Payroll" allowance in Table A in paragraph 2.2(b)(vi) to include the (additional) delta in DB pension scheme employer contributions:*

	Tariff Year					
Defined Benefit Pension Scheme Employer Contributions	**2015/ 2016**	**2016/ 2017**	**2017/ 2018**	**2018/ 2019**	**2019/ 2020**	**Total**
Delta	-468,000	-316,000	-261,000	-247,000	-197,000	-1,489,000

(iv) *amend K_{TSOt} in paragraph 2.2(f) by adding an additional component to the F_{TSOt-2} formula as follows*:

> *minus*
>
> (D) *that part (if any) of the efficiently incurred costs of any Transmission Network Pre-Construction Project, which proceeded to construction and for which full payment has been received, already provided for in Table A at paragraph 2.2 (b)(vi)*

(B) Relief sought in respect of pension deficit recovery

46.17 The Utility Regulator has also imposed a cut-off date of 31 March 2015 in respect of the Appellant's historical deficit, without appropriate consultation and without adequate regard to the Appellant's circumstances.

46.18 In addition to the amendment proposed above to paragraph 8.1(d) of Annex 1, the Appellant therefore requests that the CMA direct the Utility Regulator that to the extent it decides to consult further on pension deficit recovery, that such consultation should include the question as to whether it is appropriate, in the Appellant's particular circumstances, to adopt a "cut-off date". The Appellant also requests that the CMA direct the Utility Regulator that, to the extent it does decide to impose a cut-off date, this can only apply prospectively.

(iii) Error 11: Relief sought in respect of the Utility Regulator's failure to provide an adequate IS capex allowance

(A) Relief sought in respect of the exclusion of DS3/Smart Grids

46.19 The Appellant has been materially underfunded by £1,333,000 over the Price Control Period for the delivery of "DS3/Smart Grids" as the Utility Regulator has erroneously excluded this area from the IS capex allowance.

46.20 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below.

Requested remedy: The CMA is requested to make the following amendments to Annex 1 of the TSO Licence:

(i) amend the "Depreciation on Non-Building Assets" allowance in Table A in paragraph 2.2(b)(vi) to include the £1,333,000 (full forecast) expenditure expected to be incurred in delivering the outputs of the "DS3/Smart Grids" CapEx programme; and

(ii) amend the "rate of return allowance" in Table B of paragraph 2.2 (b)(vii) to reflect the WACC return associated with the £1,333,000 forecast expenditure, in line with its forecast expenditure profile and standard regulatory depreciation treatment.

(B) Relief sought in respect of the incorrect adjustment for inflation

46.21 The Appellant has been underfunded by £291,000 over the Price Control Period due to an error made by the Utility Regulator in carrying out a "rebasing" exercise against the full forecast cost.

46.22 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below.

Requested remedy: The CMA is requested to make the following amendments to Annex 1 of the Licence:

(i) amend the 'Depreciation on Non-Building Assets' Allowance in Table A of paragraph 2.2(b)(vi) to reinstate the sum of £291,000 expected to be incurred in delivering the outputs of the IS capex programme; and

(ii) *amend the "rate of return allowance" in Table B of paragraph 2.2(b)(vii) to reflect the WACC return associated with the £291,000 forecast expenditure, in line with its forecast expenditure profile and standard regulatory depreciation treatment.*

(b) Relief sought in respect of the Revenue Uncertainty Ground

46.23 The Appellant is seeking relief in respect of a number of errors made by the Utility Regulator in its approach to managing uncertainty for the Price Control Period. These errors have been explained in Part IV of the Notice. In summary, the Utility Regulator has determined that a very significant proportion of the revenues will be subsequently determined either under a general "Dt" mechanism (designed to facilitate recovery of "unforeseen" or pass-through costs), through a separate and as-yet-unspecified process, or not at all.

46.24 The Appellant estimates, based on its current knowledge, that the Decision will result in approximately £37 million being separately reviewed and approved outside of the Price Control, in the context of an overall Price Control settlement of £69 million (representing some 35 per cent of total revenues).

46.25 On an individual and cumulative basis, these errors have a negative impact on the Appellant. The inherent financial risk stemming from the significant uncertainty across the Price Control Period will affect the ability of the Appellant to attract financing, which may compromise the efficient delivery of the price control outputs with a corollary effect on consumers.

(i) <u>Error 2: Relief sought in respect of the Utility Regulator's failure to provide a recovery mechanism for the costs associated with PCNPs</u>

46.26 The Decision fails to provide a means for cost recovery for PCNPs under the TSO Licence (save for the costs of any abandoned projects which are to be recovered under the Dt mechanism, subject to assessment against efficient costs and an *ex ante* cap), meaning there is a complete absence of certainty as to the process for recovering a significant portion of costs. This makes it extremely difficult for the Appellant to demonstrate that it will be allowed its efficient costs in a timely manner to be able to meet lenders' requirements regarding the provision of finance.

46.27 The Appellant requests that the CMA correct the Utility Regulator's error by modifying the Licence as proposed below. For the avoidance of doubt the Appellant has proposed a separate remedy (under Error 4) for those PCNPs which qualify to be treated as Significant Projects by virtue of their costs exceeding £1 million.

46.28 The preferred remedy has five elements. The first involves the inclusion of additional definitions in Annex 1 and to amend the definition of "Transmission Network Pre-construction Project" to remove the requirement for *ex ante* approval and to clarify that it is the Appellant (and not NIE) who has responsibility for identifying those projects necessary for the purposes of developing the transmission system. Secondly, the four possible scenarios for progression of PCNPs should be explicitly included in the TSO Licence, and the TSO Licence should refer to the appropriate cost recovery mechanism for each. The third element should not be subject to the 50:50 risk share mechanism (so can be explicitly excluded from the BI_t adjustment in paragraph 2.2(c) of Annex 1). The fourth element should prescribe that cost recovery in respect of PCNPs may only be adjusted by the Utility Regulator by way of *ex post* assessment, and that in the interests of efficiency any such *ex post* assessment must take place within three months of invoice submission to the constructing party (which will settle such invoice as per the arrangements applicable to that party) after which there would be no ability to make additional adjustments. Finally, the "side RAB", or interim RAB which arises during the development of a PCNP up to the construction phase, should be codified within the TSO Licence.

46.29 Where projects proceed to construction to NIE (expected to be the typical case), the Appellant also requests that the TIA be amended to reflect the Appellant's proposals (as suggested below).

<u>Requested remedy</u>: The CMA is requested to amend Annex 1 of the TSO Licence as follows:

(i) *extend to Annex 1 the existing definitions of "Commission Decision" and "Transmission Interface Arrangements" as applicable to Condition 18 of the TSO Licence*

(ii) *amend the definition of "Transmission Network Pre-construction Project" in paragraph 1.1 as follows*:

means a transmission network project

(a) identified by the Licensee as a project which is necessary for the purposes of developing the transmission system;

(b) and for which the Licensee is responsible for activities that are required to progress the project from the conception stage up to (but not including) the construction stage

(iii) *add a new definition entitled "Transmission Network Preconstruction Project Costs", to mean any such costs as are recoverable by the Licensee under paragraph 11*

(iv) *amend paragraph 2.2(c) by adding after (ii) the following text*:

But shall in all cases exclude any adjustments associated with Significant Projects which are also Transmission Network Pre-Construction Projects.

(v) *add a new paragraph 11 entitled: "Transmission Network Pre-construction Project", providing:*

(A) *where a Transmission Network Pre-construction Project proceeds to NIE for construction all reasonably and efficiently incurred costs shall be recoverable from NIE pursuant to Section N of the TIA and Condition 18 of the Licence; and*

(B) *where a Transmission Network Pre-construction Project proceeds to another entity for construction all reasonably and efficiently incurred costs shall be recoverable from that entity, pursuant to the applicable interface arrangements; and*

(C) *where the Licensee agrees to construct a Transmission Network Pre-construction Project, either acting as constructor or in exercising its Step-in rights in accordance with the provisions of Section O of the TIA and Paragraph 60 of the Certification Decision, all reasonably and efficiently incurred costs shall be recoverable and provided for by the Authority in a manner timely enough, and without adverse impact on the Appellant's financeability, to ensure the Step In rights are meaningful and effective.*

(vi) *provide within new paragraph 11 that all reasonable and efficient Transmission Network Pre-construction Project Costs incurred shall be recoverable in accordance with the arrangements as set out in (iv) above, subject to ex post adjustment for demonstrably inefficient or wasteful expenditure, such adjustment to be determine within three months of the date of submission to the Authority for approval*

(vii) *amend paragraph 2.3 to:*

(A) *redefine the Rate of Return as* RAB_t *x* $WACC_t$ *plus* RAB_PC_t *x* $WACC_t$

and

(B) *add a new paragraph 2.3(c) to read:*

(c) RAB_PC_t *means*

(i) the Regulated Asset Base relating to Transmission Network Pre-construction Project Costs and:

(ii) is calculated in accordance with the following formula:

$RAB\_PC_t = (OTNPPC_t + CTNPPC_t)/2$

where

(iii) $OTNPPC_t$ *is the opening value of Transmission Network Project Pre-construction Costs in Year t*

(iv) $CTNPPC_t$ *is the closing value of Transmission Network Project Pre-construction Costs in Year t*

(vi) $CTNPPC_t = OTNPPC_t + ADDPCC_t - TRNPPC_t$

where

(vii) $ADDPCC_t$ *is additional Transmission Network Project Pre-construction Costs incurred in Year t, and*

(viii) $TRNPPC_t$ *is Transmission Network Project Pre-construction Costs transferred to a third party in Year t*

46.30 The above would also require the CMA to direct the Utility Regulator to make any necessary amendments to the TIA to align with the above licence amendments, including:

(i) amendment to Section U (Definitions) by deleting "*and approved by the Authority*";

(ii) amendment to Section N (Charges and Payments) by removing from paragraph 4.7 "*pursuant to a direction, other decision*";[421]

[421] This is required to ensure the Appellant is paid its efficiently incurred costs in a timely manner which ensures its financeability and to prohibit the Utility Regulator suspending such payments as per its letter of 12 November 2014 to both the Appellant and NIE.

(iii) amendment to Section N (Charges and Payments) by adding to paragraph 3.2 "*and shall include the appropriate inflation RPI adjustment*".

(ii) Error 3: Relief sought in respect of the Utility Regulator's failure to provide a recovery mechanism for the costs associated with any additional capital investment in information systems

46.31 In addition to the failure to make appropriate provision for the Appellant's IS capex submission (Error 11) and the application of a stretched efficiency target of c.10% across the entirety of the IS capex submission in the Business Plan, the Appellant is expected to deliver any other IS capex requirements which may arise during the course of the Price Control Period. It is unclear what mechanism, if any, the Appellant may utilise to submit additional expenditure on IS capex for approval, as the Utility Regulator has indicated it will not approve Dt submissions made in relation to IS capex investments.

46.32 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision modifying the TSO Licence as proposed below. This amendment would permit the recovery of additional IS capex via the Dt mechanism. For the avoidance of doubt the Appellant has proposed a separate remedy (under Error 4) for those IS capex projects which qualify to be treated as Significant Projects by virtue of their costs exceeding £1 million.

Requested remedy: The CMA is requested to amend Annex 1 of the TSO Licence by inserting new sub-paragraph (j) into paragraph 8.1 as follows*:*

(j) any reasonable and efficient costs incurred by the Licensee in delivering additional IS capex outputs which are not Significant Projects.

(iii) Error 4: Relief sought in respect of the Utility Regulator's failure to provide a suitable recovery mechanism for revenues associated with Significant Projects

46.33 The Utility Regulator failed to provide a suitable recovery mechanism for Significant Projects, preferring to expand the use of the existing Dt mechanism, or an unspecified mechanism in the case of PCNPs, in the Price Control formula – under which costs are incurred and submitted as claims for *ex post* approval.

46.34 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the TSO Licence to insert an uncertainty mechanism measure specific to "Significant Projects" (as defined below), which would provide for an interim review of costs subject to an upward adjustment. This provides the Appellant and other stakeholders with transparency over the Utility Regulator's decisions in respect of allowable revenues and a suitable right of appeal in respect of decisions on Significant Project allowances. For the avoidance of doubt, the TSO Licence should clarify that those Significant Projects which are also PCNPs should not be subject to the 50:50 risk share mechanism. These costs should therefore be excluded from the BI_t adjustment in the TSO Licence (in the same manner as suggested for Error 2).

46.35 The Appellant also requests that the CMA modify the Licence to amend the definition of "Price Control Decision Paper" to correct the dates referenced therein, and to remove the third limb of the existing definition, which entitles the Utility Regulator to supplement its Decision with further papers.

<u>Requested remedy</u>: The CMA is requested to make the following amendments to Annex 1 of the TSO Licence:

(i) *add to paragraph 1.1 the following definition of Significant Projects*:

Significant Project means any activity or project undertaken by the Licensee where the forecast costs are greater than £1 million

(ii) *add to paragraph 2.1*:

<u>Plus</u>

(c) any amounts that the Authority, its SEM Committee, or the Licensee has proposed, for pre-approval, in respect of any Significant Project.

In each such instance Tables A and B of this Annex shall be amended accordingly.

(iii) *amend paragraph 2.2(c) by adding after (ii) the following text*:

But shall in all cases exclude any adjustments associated with Significant Projects which are also Transmission Network Pre-Construction Projects.

(iv) *amend in paragraph 1.1 the definition of "Price Control Decision Paper" as follows:*

Price Control Decision Paper means each of (i) the decision paper issued by the Authority on 24/02/2016 and entitled "Final Determination to the Price Control 2015-2020 for the Electricity System Operator for Northern Ireland (SONI) and (ii) the decision paper issued by the Authority on 14/03/2017 and entitled "Decision on the Licence Modifications for the Price Control 2015-2020 of the Electricity System Operator for Northern Ireland (SONI)".

(iv) <u>Error 5: Relief sought in respect of the Utility Regulator's failure to provide a suitable right of appeal concerning decisions on the recovery of cost associated with Significant Projects</u>

46.36 A further consequence of Error 4 is that the Appellant is not able to appeal such material funding decisions to the CMA. Due to the significance of the revenues involved, it is imperative that there is a right of appeal available to relevant stakeholders against any determination in respect of the Significant Projects. It is insufficient and would be disproportionate that the Appellant's only right of challenge would by way of judicial review to the High Court, a non-specialist court which would not be able to hold the Utility Regulator to proper account on review of funding decisions.

46.37 As the introduction of amendments to the Appellant's licence automatically provides this right of appeal to the CMA by virtue of Article 14B of the Electricity Order, the Appellant considers the relief set out in respect of Error 4 above to provide an appropriate appeal right.

(v) <u>Error 6: Relief sought in respect of the Utility Regulator's failure to manage uncertainty by creating additional uncertainty through implementing an unworkable two-stage process</u>

46.38 The Utility Regulator failed in its task to effectively manage uncertainty by purporting to implement a two-stage approval process for uncertain costs which has a downside-only risk feature. This requires the Appellant to submit Dt claims for pre-approval up to a cap and must later report the actual costs which are then subject to an adjustment mechanism. The result is unworkable, given the Dt mechanism is designed to facilitate recovery of unforeseen costs. Further, the mechanism is inefficient and unlikely to result in any greater benefit to consumers.

46.39 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below. Such costs would remain subject to assessment under the demonstrably inefficient and wasteful expenditure (**DIWE**) provision.

46.40 There are two limbs to this remedy: first, certain categories of "uncontrollable" costs which are suitable to treat on a pass-through basis should be transferred from the D_{TSOt} term to the Atsot component; and secondly, paragraph 8.1 should be amended and the AD_{TSOt-2} term should be deleted from Annex 1 as required in order to replace the two-stage approval process with a straightforward *ex post* DIWE adjustment (such adjustment to take place only in accordance with the guidance required to remedy Error 7, as discussed below).

Requested remedy: The CMA is requested to amend Annex 1 of the Licence as follows:

(i) *delete paragraph 8.1(g) and amend paragraph 2.2(a) by adding the following category for costs over which the Appellant has no control to the Atsot component, which can be submitted as part of the of the annual maximum core SSS/TUoS revenue in Relevant Year t (Mtsot):*

iv) any amounts that the Authority approves as uncontrollable costs where the ex post actual amount is lower than £1 million. This would include but would not be limited to the costs associated with:

(A) *the Licensee's membership of the European Network of Transmission System Operators for Electricity (ENTSO-E);*

(B) *the Licensee's obligations under and in accordance with the ENTSO-E Inter TSO Compensation Agreement;*

(C) *the Licensee's participation on a mandatory basis in Regional Security Coordination Initiatives (RSCIs) as a member of ENTSO-E;*

(D) *the Pension Scheme Costs [as defined in respect of the remedy to Error 10 above] (in Relevant Year t) of the Transmission System Operator Business to the extent not recovered under any other provision of this Licence;*

(D) *the rates charged to the premises of the Transmission System Operator Business;*

(E) *the Licence Fee levied on the Transmission System Operator Business,*

(ii) *amend paragraph 8.1 of Annex 1 "Excluded SSS/TUoS" to remove references to "(or likely to be incurred)"*

(iii) *delete paragraph 2.2(f)(i)(B) and (C) in their entirety and replace with new (B) which states (DTSOt-2 – that part of DTSOt-2 that the Authority determines to be Demonstrably Inefficient or Wasteful Expenditure)*

(vi) Error 7: Relief sought in respect of the Utility Regulator's unjustified creation of additional uncertainty through failing to provide guidance on how it will apply the demonstrably inefficient and wasteful expenditure (DIWE) provision

46.41 The Utility Regulator erred in respect of its failure to issue guidance as to the application of a new mechanism that allows it to disallow recovery of costs or to claw-back funds from the Appellant where it deems the expenditure was inefficient or wasteful. This is despite previously proposing in its Draft Licence Modifications that guidance would be forthcoming.[422]

46.42 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below. The Appellant also requests that the CMA issue a direction requiring the Utility Regulator to implement such guidance, as proposed below.

Requested remedy: The Appellant requests that the CMA add new paragraph 10 to Annex 1 of the Licence as follows:

*10 **Demonstrably Inefficient and Wasteful Expenditure***

10.1 For the purposes of the provisions of this Annex in which the term Demonstrably Inefficient or Wasteful Expenditure is used:

(a) the term shall be interpreted and applied only in accordance with guidance to be issued on or before the date six months following publication of the CMA's determination (following consultation with the Licensee); and

(b) any determination made by the Authority entailing the interpretation and application of the term shall be accompanied by a statement of its reasons.

With regard to (a) above the CMA is also requested to issue a direction to the Utility Regulator requiring it to consult upon and to implement appropriate guidance in a reasonable timeframe (which the Appellant considers to be six months of publication of the CMA's determination).

(vii) Error 8: Relief sought in respect of the Utility Regulator's unjustified creation of additional uncertainty through the introduction of the Qt adjustment

46.43 At the final stage of the Price Control process, the Utility Regulator added the "Qt" adjustment as a new component of the price control formula, without consultation. This enables the claw-back of any "over-payment" on tariffs on a retrospective basis. The Appellant considers that the clause is unreasonably wide in scope as there is an absence of any limit on the scope of the adjustments that can be applied to the maximum revenue cap for the year ending 30 September 2017. As a result of the total lack of consultation (the adjustment having only been introduced in the Decision) the Appellant has no certainty as to how the provision will be applied.

46.44 The Appellant requests that the CMA quash the Utility Regulator's decision and substitute its own decision by modifying the Licence as proposed below.

Requested remedy: The CMA is requested to remove all references to the Qt term by amending Annex 1 of the Licence as follows:

422 Draft Licence Modifications, paragraph 9.1 [**NOA1/16**].

(i) *remove paragraph 2.2 (e); and*

(ii) *remove the Qt term from the price control formula in paragraph 2.2 so it reads as follows:*

The maximum core SSS/TUoS revenue shall be calculated as follows:

MTSOt = ATSOt + BTSOt - BIt + DTSOt + KTSOt + INCENTt

(c) Relief sought in respect of the Financeability Methodology Ground (Ground 1)

46.45 Even assuming the correction of the errors described above, the Utility Regulator has failed to employ a revenue framework which is capable of securing the Appellant's financeability.

46.46 The Appellant requests that the CMA introduce a margin-based approach in order to secure its financeability. KPMG2 provides further details about designing and implementing a margin-based approach. KPMG1 assesses the appropriate level at which the margin should be set to secure the Appellant's financeability.

46.47 In summary, the Appellant requests that the CMA amend the Licence so as to provide for the recovery of a margin of 11 per cent on controllable costs. Proposed text for this licence modification is provided below.

Requested remedy: The CMA is requested to add new terms '$MARG_t$' such that:

The maximum core SSS/TUoS revenue shall be calculated as follows:

$M_{TSOt} = A_{TSOt} + B_{TSOt} - B_{It} + D_{TSOt} + K_{TSOt} + INCENT_t + MARG_t$

MARG in Relevant Year t, which for each Relevant Year t in the period 1 October 2015 to 30 September 2020 is calculated in accordance with the following formula:

$MARG_t = ((B_{TSOt} \text{ x } MARG) + (ADDPCCt \text{ x } MARG) + (DTSOt \text{ x } MARG)) / (1 – MARG)$

Where;

MARG = allowed margin on controllable costs listed in Table C

Table C

Relevant Year t	**1**	**2**	**3**	**4**	**5**
MARG	11%	11%	11%	11%	11%

46.48 As discussed in KPMG2, the Appellant would, in addition, need to be remunerated for the cost of providing working capital. As discussed in KPMG2, the Appellant would, in addition, need to be remunerated for the cost of providing working capital. KPMG notes that:[423]

If the margin is applied to controllable (net) revenues only, the working capital cost associated with pass-through costs would not be remunerated. This means that a separate allowance would need to be applied to cover any standby debt facilities.

423 KPMG2, paragraph 1.1.27 **[MC1/2]**

47 Conclusion

47.1 The total value of the relief sought in this Notice equates to £13.2 million. This is in addition to the various reliefs and clarity sought in relation to uncertainty and risks. Taken in combination it is the view of the Appellant that they will enable the efficient discharge by it of its functions and render it financeable.

47.2 Given the nature of the Appellant's business, and the importance of its financeability to businesses and consumers in Northern Ireland, the application of these remedies is also consistent with the Utility Regulator's Principal Objective.

48 Statement of Truth

48.1 I believe that the facts stated in this Notice are true.

Signed …………………………………

Name …………………………………

Dated …………………………………

For and on behalf of the Appellant.

ANNEX I

CHRONOLOGY

Date	Event
15 February 2013	The SEM Committee publishes its preliminary TSO Certification Decision
12 April 2013	European Commission decision of 12.4.2013 pursuant to Article 3(1) of Regulation (EC) No 714/2009 and Article 10(6) of Directive 2009/72/EC – United Kingdom (Northern Ireland) – SONI/NIE
20 September 2013	The Utility Regulator publishes its consultation on measures for the purposes of the EU Third Internal Energy Package
5 December 2013	Meeting between the Appellant and the Utility Regulator to discuss the structure of the process for the 2015-2020 Price Control review, due to take effect upon the expiry of the 2010-2015 Price Control on 30 September 2015
2 February 2014	The Appellant submits the Principles & Key Issues paper to the Utility Regulator
6 March 2014	Meeting between the Appellant and the Utility Regulator in respect of the recovery framework for transfer of investment planning
27 March 2014	Meeting between the Appellant and the Utility Regulator to discuss transfer of the Network Planning function, SONI Price Control and regulatory accounts
28 March 2014	Publication of the revised TSO Licence transferring responsibility for network planning to the Appellant
30 April 2014	Execution of an Implementation Agreement between NIE and the Appellant relating to transfer of transmission system investment planning function
1 May 2014	Transfer of NIE staff to the Appellant takes effect
1 July 2014	Letter from the Utility Regulator to the Appellant notifying it of the final decision on the certification of the Appellant as TSO
9 July 2014	The Utility Regulator publishes the Approach Paper
21 October 2014	SONI submits its Business Plan
5 December 2014	Meeting between the SONI Board, members of the EirGrid Board, and the Utility Regulator Board to discuss the treatment of Network Planning, the ongoing Price Control review and the appropriateness of the continuing application of the RAB*WACC regulatory framework
22 December 2014	Publication of the Position Paper
January-July 2015	The Appellant provides responses to the Utility Regulator’s queries in respect of its Business Plan
2 April 2015	The Utility Regulator publishes the Draft Determination
18 May 2015	The Appellant makes submissions in response to the Draft Determination

June – August 2015	The Appellant provides responses to the Utility Regulator's queries in respect of its response to the Draft Determination
4-9 December 2015	The Utility Regulator provides the Appellant with a copy of its draft Final Determination for factual review and draft Licence Modifications
11-15 December 2015	The Appellant provides its responses to the factual review of the draft Final Determination
24 February 2016	The Utility Regulator publishes the Final Determination and consultation on the Draft Licence Modifications to the TSO Licence
23 March 2016	The Appellant provides its response to the Utility Regulator's statutory consultation on the Draft Licence Modifications to the TSO Licence
13 May 2016	Response from the Utility Regulator relating to the Utility Regulator's statutory consultation on the Draft Licence Modifications to the TSO licence
7 June 2016	Meeting between the Utility Regulator and the Appellant to discuss the Draft Licence Modifications
14 June 2016	Follow-up submission from the Appellant on the Utility Regulator's statutory consultation on the Draft Licence Modifications to the TSO licence
11 January 2017	The Utility Regulator provides the Appellant with a draft of the Final Licence Modifications and accompanying Decision Paper in advance of publication
19 January 2017	Meeting between the Utility Regulator Board and representatives of the EirGrid and SONI Boards
14 March 2017	The Utility Regulator publishes the Decision Paper and Final Licence Modifications

ANNEX II

LIST OF GROUNDS

The Grounds of Appeal are explained in detail in Part IV of this Notice and are summarised here for ease of reference.

Ground 1 – The Financeability Methodology Ground

- Error 1(a): The Utility Regulator failed to adopt a price control framework that could secure the Appellant's financeability.
- Error 1(b): The Utility Regulator's limited and inadequate financeability assessment was subject to material errors.
- Error 1(c): The Utility Regulator failed to undertake a complete financeability assessment which – had it done so – would have demonstrated that the Appellant is not financeable.

Ground 2 – The Revenue Uncertainty Ground

- Error 2: Failure to provide a cost recovery mechanism for PCNPs.
- Error 3: Failure to provide a cost recovery mechanism for additional IS capital investment.
- Error 4: Failure to provide a suitable cost recovery mechanism for Significant Projects.
- Error 5: Failure to provide a suitable right of appeal concerning decisions regarding cost recovery for Significant Projects.
- Error 6: Failure to manage uncertainty by creating additional uncertainty through implementing an unworkable two-stage approval process.
- Error 7: Unjustified creation of uncertainty through failure to provide guidance on the application of the DIWE provision.
- Error 8: Unjustified creation of uncertainty through the introduction of the Qt adjustment.

Ground 3 – The Inadequate Allowances Ground

- Error 9: Failure to provide adequate payroll allowances for network planning staff.
- Error 10: Failure to provide adequate pensions allowances.
- Error 11: Failure to provide an adequate IS capital expenditure allowance.