<u>BEFORE THE COMPETITION AND</u>

<u>MARKETS AUTHORITY</u>

BETWEEN:

(1) SSE GENERATION LIMITED

(2) THE ENTITIES LISTED IN SCHEDULE 1

<u>Appellants</u>

- and -

THE GAS AND ELECTRICITY MARKETS AUTHORITY

<u>Respondent</u>

AN APPEAL UNDER SECTION 173 ENERGY ACT 2004

Appellants

(1) SSE Generation Limited ('SSE'), No. 1 Forbury Place, 43 Forbury Road, Reading, RG1 3JH

(2) The entities listed in Schedule 1 hereto, being either the parent, subsidiary or affiliate companies within the SSE corporate group that are licensed electricity generators

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(for the purposes of this application, GEMA may also be referred to as "Ofgem" below and in accompanying documents).

Potentially affected parties

A copy of this application for Permission to Appeal and accompanying documents has been sent to those persons[1] who appear to the Appellants to be affected by the Decision in accordance with rule 4.4 of the Energy Code Modification Rules (CC10) ('the Rules'). A list of those parties is contained in Schedule 2.

[1] Based on: (i) those who responded to the Workgroup stakeholder consultations for CMP317 and CMP327 which closed on 23 March 2020, as set out in Annex 10 of the CMP317/327 Final Modification Report ('FMR') dated 13 August 2020; and (ii) those who responded to the stakeholder (Code Administrator) consultation for CMP317 and CMP327 which closed on 20 July 2020, as set out in Annex 19 of the same FMR. No additional persons in fact responded to the separate CMP339 stakeholder (Code Administrator) consultation procedure which closed on 20 July 2020.

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A. INTRODUCTION AND SUMMARY

1. The Appellants ('SSE', save where the identity of a specific Appellant is relevant) seek permission from the Competition and Markets Authority ('CMA') pursuant to section 173(4) of the Energy Act 2004 ('EA 2004') to appeal against a decision of the Gas and Electricity Markets Authority ('GEMA') dated 17 December 2020 ('the contested Decision').[2] By the contested Decision, GEMA:
   1.1. approved an original proposal raised on 21 May 2019 for a modification to the Connection and Use of System Code ('the CUSC') which stipulates the Transmission Network Use of System ('TNUoS') charges levied by the Transmission System Operator ('TSO'), National Grid Electricity System Operator Ltd ('NGESO').[3] The proposal related to the *Identification and exclusion of Assets Required for Connection when setting Generator Transmission Network Use of System (TNUoS) Charges* ('CMP317', also known as the 'Original Proposal'); and
   1.2. approved the proposal raised on 28 November 2019 in CMP327 *Removing the Generator Residual from TNUoS Charges* ('CMP327').[4]

2. SSE also seeks permission to appeal against the consequential decision of GEMA dated 17 December 2020 concerning *Consequential changes for CMP317 and CMP327 (TCR)*, ('CMP339'), which seeks to give effect to the contested Decision through the introduction of relevant definitions, as well as amendments to existing definitions, in the CUSC.

3. In very summary form, the effect of the acceptance of the Original Proposal is that the 'Connection Exclusion' found in Part B of the annexed Guidelines to Commission Regulation (EC) 2010/838[5] ('the ITC Regulation') has been construed by GEMA as extending to Local Charges associated with the use of Local Circuits and Local Network assets, rather than just assets associated with offshore Generation Only Spurs ('GOS'). It

[2] The contested Decision is not excluded from the right of appeal pursuant to section 173(2)(d) EA 2004 and the Electricity and Gas Appeals (Designation and Exclusion) Order 2014, SI 2014/1293.
[3] This follows GEMA's decisions of 4 September 2018 and 1 April 2019 concerning the separation of the system operation ('SO') function from National Grid Electricity Transmission Plc into NGESO. A Glossary of the many acronyms used in this field is attached to this Notice of Appeal.
[4] The CUSC procedure commenced by the Original Proposal in CMP317 was later amalgamated with CMP327, as set out below. The contested Decision accordingly covers both CMP317 and CMP327.
[5] Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, OJ [2010] L No 250, 24.9.2010, p. 5.

has also construed the ‘Ancillary Services Exclusion’ in the ITC Regulation as encompassing: (i) charges for Congestion Management found in the Balancing Services Use of System charges (‘the relevant BSUoS Charges’) paid by transmission connected Generators and (ii) some of the funding share costs associated with the Balancing Settlement Code (‘BSC’)[6] which have to be paid by transmission connected Generators (‘the relevant BSC Charges’). This has the intended result of avoiding a situation in which the statutory range on the annual average transmission charges paid by Generators of €0.00-2.50 MWh (set by the ITC Regulation) is otherwise breached.

4. The First Appellant is a Generator with significant offshore and onshore generating assets and is therefore exposed to a far higher degree of transmission costs than would be the case if the statutory range were properly respected by the contested Decision. The other companies listed as Appellants in Schedule 1 are each holders of licenses issued by GEMA to generate electricity and/or asset owners i.e. Generators. They are also directly and materially affected by the contested Decision.

5. Following the agreement of GEMA on 29 January 2020, CMP317 was joined with CMP327. CMP327 was proposed by NGESO to give effect to GEMA’s Direction[7] that the Transmission Generation Residual charge (‘TGR’) should be set at zero for the purposes of the system of charging Generators for their share of the common costs of the use of the Great Britain (‘GB’) transmission network (‘TNUoS charging’). The contested Decision also approved CMP327. SSE does not object in principle to the TGR being set at zero. But it considers that another means of adjusting transmission charges payable by Generators should be applied, such that the average amount paid by Generators for the costs of transmission does not exceed the statutory range. A mechanism for such an adjustment is now found in Condition 14.14.5 of the CUSC, following the amendments made by CMP339.[8]

[6] The Relevant BSC Charges as defined in the legal text accompanying the Original Proposal.
[7] The Direction was made in November 2019 following the conclusion of the Targeted Charging Review (‘TCR’) as part of a Significant Code Review (‘SCR’) procedure. The Direction required TGR to be set at zero while nonetheless respecting the statutory range on transmission charges set by the ITC Regulation.
[8] CMP339 defines “Adjustment Tariff” as the “non locational £/kW tariff that applies Adjustment Revenue to Generators liable for TNUoS charges to ensure compliance with the Limiting Regulation.” Adjustment Revenue is defined “a positive or negative adjustment to overall Generator TNUoS charges to ensure compliance with the Limiting Regulation.” However, CUSC condition C14.14.5(vii) makes clear that this adjustment is only applied after the Connection Exclusion has been taken into account, meaning that the proper construction of the Connection Exclusion must be determined as a first step.

6. By a separate decision also dated 17 December 2020 in CMP339, GEMA approved an Original Proposal for a series of consequential changes to be made to the CUSC in the light of CMP317 and CMP327. SSE does not object in principle to these changes, which necessarily follow on from the conclusions of CMP317/327. Nonetheless, since SSE does object to the outcome of CMP317, an appeal is also brought against the findings in each of CMP327 and CMP339 for the sake of consistency. In the event that the contested Decision is quashed, the decisions in CMP327 and CMP339 would also necessarily be invalidated, since they stand or fall together.

7. SSE advances the following grounds of appeal against the contested Decision:

   7.1. First, GEMA's construction of the 'Connection Exclusion' in the ITC Regulation is wrong in law and/or based on clearly erroneous appraisals of fact as to the nature of charges incurred which are required for connection of a Generator to the relevant electricity transmission system.

   7.2. Secondly, GEMA's Decision is vitiated by its recognition that the Original Proposal does not apply the correct interpretation of the 'Connection Exclusion' regardless of whether or not SSE's construction is the right one. The contested Decision infringes a number of principles of public law. It is internally inconsistent and/or procedurally flawed in being motivated by an improper purpose of avoiding a breach of the ITC Regulation at all costs, rather than applying the legally correct definition and making appropriate adjustments other than through the TGR. GEMA unlawfully excluded relevant considerations from its analysis of what could be done.

   7.3. Thirdly, GEMA's construction of the Ancillary Services Exclusion and its treatment of: (i) the relevant BSUoS Charges; and (ii) the relevant BSC Charges is wrong in law.

   7.4. Fourthly, GEMA made fundamental errors of appraisal which led to it overstating the Consumer benefit and understating the Generator detriment, including the detriment to the long-term generation of renewable energy, arising from the contested Decision.

   7.5. Fifthly, GEMA should have followed a policy which aimed at achieving a level of annual average charging for Generators for transmission costs which tended towards €0.00/MWh, as a matter of good regulatory practice and in order to have proper regard and give due weight to its statutory objectives and the Applicable CUSC Objectives ('ACOs').

7.6. Sixthly, GEMA erred in failing to put in place transitional arrangements for the introduction of the change to set the TGR at £ zero. Some form of phasing of the introduction of the change would have ameliorated many of the financial disadvantages and economic disturbance suffered by Generators as a result of the contested Decision. In so doing, GEMA again failed to have proper regard and give due weight to its statutory objectives, including good regulatory practice, and the ACOs.

8. There has therefore been a consequential failure to deal with the likely breach of the ITC Regulation, which will arise from the setting of the TGR to £ zero. This is not a discrete ground as such, but the likely consequence of the other errors of fact and/or law identified in Grounds 1 to 5 above. Ground 6 goes principally to the question of relief. The relief sought by SSE is set out in Section G below.

B. APPLICATION FOR PERMISSION TO APPEAL

9. The Appellants respectfully seek permission to appeal from the CMA on the basis that:
   9.1. The appeal has a real prospect of success, as GEMA's interpretation of the ITC Regulation is wrong in law and/or fact; vitiated by the breach of various public law principles; and/or the contested Decision adopts a wrong regulatory approach.
   9.2. The appeal raises important questions of EU and domestic law and its application to the GB energy market that have not previously been definitively determined. It represents a further extension of the approach to transmission charging for Generators which was not sanctioned by the decision of the CMA in EDF Energy (Thermal Generation) Ltd and SSE Generation Ltd v. GEMA, 26 February 2018 ('the CMA Decision'). That appeal was given permission to appeal by the CMA.
   9.3. The contested Decision has very significant consequences for the Appellants and other GB Generators, as well as for the energy market as a whole. For GB Generators as a whole, the additional costs imposed on Generators are very considerable indeed.[9]
   9.4. The contested Decision is likely to lead to significant uncertainty in the GB generation market. By its Decision, GEMA has yet further expanded its previous regulatory practice in respect of the delineation between connection assets and transmission

[9] See the witness evidence of John Tindal on behalf of SSE dated 12 January 2021 ('*Tindal 1*') in section 6.

assets. Were it to be correct, there is significant scope for numerous regulatory and charging disputes to arise.

9.5. There is, with respect, no basis for the CMA to refuse permission on the grounds set out in section 173(5) EA 2004.

C. FACTUAL BACKGROUND

10. A detailed chronology is provided together with this Appeal,[10] along with a Glossary of terms used throughout the appeal documentation.[11]

(1) GB Electricity Transmission

11. GB's electricity transmission network transmits high-voltage electricity from where it is produced to where it is needed throughout the country.[12] The system is made up of high voltage electricity wires and cables, together with substations and other physical assets that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies, while the system as a whole is operated by a single TSO. This role is performed by NGESO. NGESO is responsible for ensuring the stable and secure operation of the whole transmission system. Most users that take power from the transmission system are connected to the distribution networks across GB. These networks carry electricity from the transmission system to industrial, commercial and domestic users. But it is not a linear system. Flows throughout the system can be affected by a given party (either Generator or Consumer) due to the need to balance supply and Demand.

12. There are currently three Transmission Network Owners ('TOs') permitted to develop, operate and maintain a high voltage network within their own distinct onshore transmission areas in GB. These are National Grid Electricity Transmission Plc ('NGET')[13] for England and Wales, Scottish Power Transmission Limited for southern Scotland ('SPTL') and

[10] [A1].
[11] [A2].
[12] See generally the witness evidence from Garth Graham on behalf of SSE dated 12 January 2021 ('*Graham 1*') at [3.1] to [3.4].
[13] NGET and NGESO are owned by the same corporate entity, National Grid PLC, however with GEMA's decisions of 4 September 2018 and 1 April 2019 concerning the separation of the system operation ('SO') function from NGET there is legal separation between NGET (TO) and NGESO (SO).

Scottish Hydro Electric Transmission plc ('SHET') for northern Scotland and the Scottish islands.[14]

13. In relation to investment decisions in electricity generation, the CMA has previously described the position as follows in the *Energy Market Investigation, Final Report*:[15]

"4.43 Between the introduction of NETA in 2001 and DECC's introduction of a Capacity Market in 2014, sunk and fixed capital costs were recovered entirely from earnings derived from energy sales in the wholesale electricity market. The decision to invest in a power project is high risk. A large capital commitment (around £0.5 billion for a mid-sized project) is required in exchange for an uncertain flow of revenues that will recoup sunk costs over decades.

4.44 In this sense, entering the traditional generation markets at scale has been equivalent to forming a long-term judgement on complex outcomes over a 20- to 50-year horizon. A decision to invest requires consideration of a wide range of factors…

4.45 The risks relating to investments are considerable and are likely to have increased in the recent past, when emissions-reductions objectives and policies have led to a rapid and substantial transformation of the capital used to generate electricity. It is a UK and EU policy goal that electricity generation will be substantially decarbonised in the coming years, yet the exact ways in which this is going to be delivered and incentivised are not yet absolutely clear, so adding to the risk of investment."

14. Generation assets can be situated in a variety of geographical, and thus electrical network, locations. The GB electricity transmission system, to which Generators apply to connect, is known as the National Electricity Transmission System ('NETS'). It consists principally of high voltage electric wires which connect power stations or substations owned and operated by Generators to transmission-connected customers, which transport electricity to end Consumers through the lower voltage distribution network. The NETS is made up of the Local Network and the Wider Network, the latter of which is referred to as the Main Integrated Transmission System ('MITS'). A MITS node is a predetermined place on the transmission system where Local Circuits can join. The Local Network comprises Local Circuits and local substation assets. Local Circuit and local substation assets comprise the electrical connection between, on the one hand, (i) one or more generating units; or (ii) one or more distribution networks (and from there on to end Consumers) or (iii) a combination of both (i) and (ii); and, on the other hand, the MITS. Unlike connection assets, the TOs may decide to build capacity in excess of that required by any specific Generator or

[14] SHET is within the corporate group headed by SSE plc.
[15] [A3].

Demand (consumption) from any specific distribution network, in order to anticipate future needs and other strategic requirements. As part of the Local Network, they form part of the NETS rather than assets used to connect to it. Generation Only Spurs ('GOS') describe assets that are being utilised solely (or very largely) by generation, predominantly for production but possibly also for some consumption. These GOS assets are owned separately[16] (following a GEMA organised tender process) by an Offshore Transmission Network Owner ('OFTO') who is licensed by GEMA and they connect to Local Circuits and local substations (on and off-shore) which belong to a TO. The following diagram produced by Ofgem[17] shows the overall system architecture:

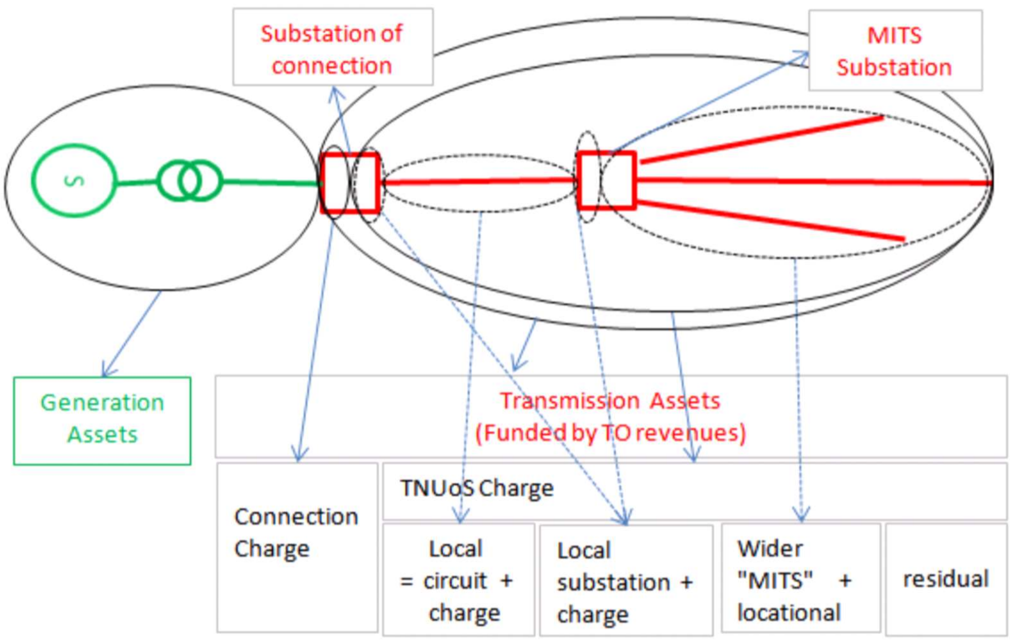

Figure 2. Transmission charge components after the proposed modification

15. The underlying evidential issues that arise in the present appeal are: (i) what constitutes the "transmission" network (and the assets within it); (ii) what constitutes a "connection" asset upon which a Connection Charge may be based; and (iii) what constitutes an "ancillary service" for which a separate charge can be made. The first and second issues are addressed in witness evidence on behalf of SSE from Garth Graham dated 12 January 2021 (*Graham 1*) and the third issue is addressed by witness evidence from John Tindal, also dated 12

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[16] Put simply, one OFTO entity owns one GOS.

[17] Impact Assessment and consultation 147/08 which related to "Charging arrangements for transmission infrastructure assets local to generation connections" dated 24 October 2008.

January 2021 (*Tindal 1*). The contested Decision represents the latest iteration from GEMA of its attempt to distinguish between electricity assets which are "transmission" assets and those which are "connection" assets, which is at variance with the definition in the NGESO Transmission Licence[18] that GEMA issues as well as the industry code's own definition of "transmission" network use of system charges and "connection" charges. It also raises a new issue with respect to GEMA's refusal to reflect a clear clarification from the EU legislature as to the proper ambit of ancillary services.

(2) The Capacity Market

16. The Capacity Market is a mechanism introduced by the Government to ensure that electricity supply continues to meet Demand. It aims to ensure there is sufficient generation or load-management capacity in the system to cope with times of stress on the system when, for example, the wind stops blowing or there is a surge in Demand.

17. Within the Capacity Market, NGESO buys capacity in the form of (£/kW/yr) ahead of delivery, to ensure there is sufficient incentive for investment in the development of new Generation and Demand management and the ongoing maintenance of existing Generation and Demand management to meet ongoing reliability standards. Pursuant to the Capacity Market rules, sufficient capacity is guaranteed by Capacity Market agreement holders at periods of system stress. Providers can rely upon a fixed income to cover some of the investment and ongoing costs not readily recoverable through the energy market.

18. There have been a number of auctions to date with, notably, contracts already awarded for periods typically up to four years ahead, and in one case for a contractual duration of 15 years. The Capacity Market was considered and described in the *Energy Market Investigation, Final Report*. For example, the CMA stated at [47]:[19]

   "The Capacity Market was introduced by DECC to help ensure sufficient investment to meet future demand. In an energy-only market, potential investors in generation might be sceptical about their ability to recover the costs of their investment, since this would require prices to be allowed to spike to very high levels on the (rare) occasions of system stress."

[18] Condition C1.
[19] [A3].

(3) TNUoS Charging and the statutory range

19. The CUSC is produced pursuant to the Transmission Licence under which NGESO operates. It is established by paragraph 2 of Standard Condition C10.[20] It is made contractually binding between NGESO as the licensee and CUSC users, such as SSE, by a CUSC Framework Agreement. In Part 1 of Section 14, it sets out the framework for 'Connection Charges'. It then separately provides in Part 2 (Section 1) of Section 14 the methodology for the calculation of TNUoS charges.[21]

20. TNUoS charges and Connection Charges (in total) recover the costs that the TOs incur in providing and maintaining transmission network assets.[22] The total costs of the transmission network are set by GEMA each year, in the form of the allowed revenue that NGESO (as the GB system operator) levies annually on transmission connected users, such as Generators, Embedded Generators over a certain size, Suppliers and directly connected Demand. The CUSC sets out, separately, the methodological means by which: (i) the Connection Charges; and (ii) the TNUoS charges are to be applied in order that the allowed revenue is recovered from Generators and Suppliers (in line with the quantity of Demand, which is also referred to as 'Load' or consumption, from end Consumers such as industrial, commercial and domestic sites that they supply).

21. In the spring following the end of each charging year (ending on 31 March) NGESO, in accordance with CUSC condition 3.13.2,[23] undertakes a reconciliation of forecast versus actual usage to take account of the data needed to apply charges in the charging year which are only available at the end of that year (i.e. after 31 March).

22. Part 2 (Section 1) of Section 14 of the CUSC sets out the methodology for the calculation of TNUoS charges. Generator TNUoS charges are based on network users' capacity and comprise a locational element and a residual element. The locational element reflects the different costs that network users impose on the network depending on where they are located. The 'residual' element historically was set to recover the remaining costs that have

[20] [A4].
[21] [A5].
[22] There are additional items, approved by GEMA, such as NGESO pass throughs and Offshore TO costs that are also recovered via TNUoS charges. See the table in [3.10] of *Graham 1*.
[23] [A5].

been allocated between Generation (G) and Demand (D) network users by the 'G:D split'. This was historically, but for the €2.50/MWh GB cap, set at '27:73.' That is, 27 per cent of transmission network costs were recovered from Generators and 73 per cent from Demand network users.

23. Generators pay 'Connection Charges' in addition to and separately from TNUoS charges. Part 1 of Section 14 of the CUSC sets out the methodology for the calculation of Connection Charges.[24] Generators also pay BSUoS Charges. The applicable methodology for BSUoS Charges is set out in Part 2 (Section 2) of Section 14 of the CUSC.

24. The ITC Regulation limits annual average transmission charges for Generators in the European Union Member States. The annual average charge for each Member State is equal to the total transmission charges collected from Generators in that Member State in a given year, divided by the total output of those Generators in that year. Charges paid by producers for physical assets required for connection to the system or the upgrade of the connection are to be excluded in this calculation (as are charges paid by Generators for ancillary services and specific system loss charges paid by Generators). The range of allowable average transmission charges for Generators in GB is €0.00-2.50/MWh, and the range for most other EU countries is €0.00-0.50/MWh. The maximum permissible level for average annual transmission charges is accordingly five times higher for GB Generation than it is for most of their counterparts in most EU Member States.

25. A useful summary of the relevant regulatory background to the charges payable by Generators under the TNUoS charging regime is set out in the CMP227 decision, which GEMA took on 15 September 2015.[25] It states:

> "Transmission Network Use of System (TNUoS) charges recover the costs that TOs incur in providing and maintaining transmission network assets. They are based on network users' capacity and comprise a locational element and a 'residual' element. The 'locational' element reflects the different costs that network users impose on the network depending on where they locate. The 'residual' element is set to recover the remaining costs that have been allocated to generation (G) and demand (D) network users by the 'G:D split'. This is currently set at "27:73", i.e. 27 per cent of transmission network costs are recovered from generators and 73 per cent from demand network users.

[24] [A5].
[25] [A6].

The Regulation limits average transmission charges for generators in European Union member states. The average charge for each member state is equal to the total transmission charges collected from generators in that member state in a given year divided by the total output of those generators in that year. The range of allowable average transmission charges for generators in Great Britain (GB) is €0-2.5/MWh, and the range for most other EU countries is €0-0.5/M Wh. GB TNUoS charges were forecast to exceed the €2.5/MWh upper limit in 2016/17. To prevent this, we approved CUSC Modification Proposal CMP224 in October 2014. CMP224 'caps' the average generation TNUoS charge in GB by setting the G:D split each year to ensure compliance with the Regulation. The G:D split is now forecast to shift in favour of generation over the next five years to a split of around 18:82 by 2020."

(4) The CMP224 decision and the rejection of subsequent proposals before CMP261

26. The possibility of breach of the €2.50/MWh threshold was raised in GEMA's "*Project TransmiT Technical Working Group*" initial report, published in September 2011.[26] The report predicted the threshold might be exceeded as early as in charging year 2015/16 or beyond.[27] It was precisely to address the risk of this breach that NGESO proposed a modification to the CUSC on 19 September 2013 (CMP224).[28] That Code Modification Proposal ('CMP') stated:

"If in any given year the average annual generation transmission charges do not fall within this range [€0-2.5/MWh], National Grid runs the risk of being non-compliant with the regulation ... Therefore it is important that the average annual generation transmission charges remain within the current prescribed range ... The driver for this [CMP224] proposal is to counter the risk of non-compliance with the EC regulation if indeed a breach of the range applied on generation transmission charges becomes a possibility in future."

27. The CMP224 proposal also stated:

"As specified in the EC regulation, the value for average annual transmission charges payable by generators is calculated by dividing the **total revenue collected from generation users through Transmission Network** Use of System (TNUoS) charges by the **total measured energy injected into the Transmission Network or simply the total demand for that year.** The total demand for any given year is an absolute number. However, the total generation TNUoS revenue can be adjusted to a level so that the average annual transmission charges payable by generators do not exceed the prescribed limit."[29] [Emphasis in original]

[26] [A7].
[27] [A10], paragraph 2.9(ii), page 12.
[28] [A9].
[29] [A9].

28. The CMP224 proposal also noted that the fixed rate of 27% recovery of TNUoS charges from Generators risked putting NGESO in breach of the upper threshold (€2.50/MWh) given the trend of year on year increases in the overall TNUoS revenue. It therefore proposed putting a cap on the annual generation TNUoS revenue, so that average annual transmission charges payable by Generators would "always stay within the range specified by the EC Regulation."[30] The proposal was that the G:D split ratio would be modified for any year accordingly. In other words, the G:D split ratio would be changed *ex ante* in Generators' favour ahead of any charging year where it was forecast that otherwise the ITC Regulation upper threshold would be exceeded.

29. GEMA directed that this proposed modification be made by a decision dated 8 October 2014 ('the CMP224 Decision').[31] GEMA also observed, based on the then current G:D split of 27:73, that the annual average transmission charges paid by Generators were expected to exceed the €2.50/MWh upper limit at some point in the five years from 2015/16 to 2020/21. The CMP224 Decision also noted:[32]

> "The proposals would set the G:D split ahead of the relevant charging year based on forecasts of the relevant variables. So there is a risk that charges exceed the upper limit of the Regulation because of forecast error. To mitigate this risk, the proposals include an 'error margin', i.e. the G:D split would be set with the target of an average transmission charge for generation that is below (rather than equal to) the upper limit allowed by the Regulation. The error margin would be set by [NGESO] each year based on its historical forecast."

30. Having assessed a series of different options from the original proposal developed by the industry Workgroup assessing CMP224, GEMA directed that the original proposal should be implemented.[33] It took effect from 22 October 2014. It is therefore open to NGESO to ensure compliance with the ITC Regulation in a given charging year by adopting the mechanism of adjusting the total TNUoS revenue collected from GB generation.

31. In terms of charges for the use of network assets, CMP224 at that stage confirmed the existing practice of treating charges associated with the use of generation-only spurs

[30] [A9].
[31] [A10].
[32] [A10].
[33] [A10].

('GOS') as well as the charges associated with 'local' circuits and/or 'local' substations as TNUoS charges rather than Connection Charges. This approach dated back at least as far as 2003[34] and was reported by GEMA to the EU Commission on a number of occasions, including in 2010, 2016 and 2020.[35] CMP 224 therefore reflected the consistent regulatory practice from GEMA in the intervening period, including its treatment of 'local' circuits and 'local' substations as network assets, rather than connection assets. This was also consistent with the treatment of charges relating to such assets under the CUSC. TNUoS charges, rather than Connection Charges, had been collected and paid by Generators on the basis of the CUSC and on the basis of GEMA's interpretation of the ITC Regulation over this period.

32. Thereafter, on a number of occasions during 2015 and 2016, the possibility that a breach of the upper limit set in the ITC Regulation could occur was raised by SSE, EDF Energy (Thermal Generation) Ltd ('EDF') and others with NGESO. There were at least eight occasions[36] on which the real risk of an infringement of the threshold was brought to NGESO's attention between January 2015 and March 2016.

33. A proposal for a CUSC modification (CMP227) was made by Intergen on 18 February 2014.[37] Intergen proposed that the G:D split of TNUoS charges should be amended to a lower figure for Generators, such as 15:85 (the historical split being 27:73.)[38] The basis for the proposal was to ensure that TNUoS charges remained within the threshold set by the ITC Regulation. lntergen commented that the proposal would enable GB Generators to compete on a more level playing field with their counterparts in other Member States.[39] That proposal was rejected by GEMA in a decision dated 15 September 2015.[40]

34. In August 2015, CMP251 was raised by British Gas ('BG').[41] This proposed the removal of the error margin[42] entirely and the introduction in its place of a system of *ex post* reconciliation payments to be passed through from Generators to Suppliers (i.e. Demand)

[34] [A11].
[35] See *Graham 1* at [3.5]-[3.16]. The details given in the report dated 31 July 2020 can be found starting at p. 29 of [A12].
[36] As set out at Paragraph 2.34, pages 10-11, of [A8].
[37] [A13].
[38] See paragraph [22] above.
[39] As well as within the UK as a Member State in terms of Northern Ireland.
[40] [A6].
[41] [A14].
[42] Which was introduced by CMP224, as set out in paragraph [29] above.

or *vice versa* from charging year 2017/18 onwards. BG requested that its proposal be addressed with urgency, but that request was rejected by GEMA. NGESO (on behalf of the CUSC Workgroup) obtained a legal opinion from Addleshaw Goddard dated 23 November 2015 to address some of the legal issues raised by the CMP251 proposal.[43] No decision was taken by GEMA on the CMP251 proposal prior to the CMP261 decision. Following the CMA's dismissal of EDF and SSE's appeal against GEMA's CMP261 decision (as described further below), GEMA also rejected CMP251 (and for the same reasons) by a formal decision dated 17 August 2018.[44]

(5) The CMP261 Decision

35. It became apparent from about 2011 that there was a real chance that the statutory cap of €2.50 MWh would be exceeded in forthcoming charging years. In the event that the upper limit were to be exceeded, the TNUoS charges and the licence condition which requires them to be paid would be in breach of directly applicable EU law. The prediction of a breach was dependent on forecast figures which applied the existing regulatory approach and the correct legal construction of the ITC Regulation, which, in keeping with the approach in the NGESO Transmission Licence and the CUSC, separated Connection Charges from TNUoS charges. In other words, those forecasts were based on the then prevailing construction of the ITC Regulation which had formed the basis of the existing charging practice and reflected the consistent distinction between TNUoS charges and Connection Charges in the CUSC. In the course of its subsequent decision in CMP261, GEMA chose to term this construction as the "narrow interpretation" of the connection costs that can be excluded from calculating that upper limit (i.e. 'the Connection Exclusion' found in the ITC Regulation).

36. SSE foresaw that the increasing level of TNUoS charges during 2015/16 would lead to it and other Generators paying annual average transmission charges which exceeded the legally permissible limit during the course of that year. Rather than seek to recover charges levied in breach of EU law on an *ex post* basis, SSE chose to raise CMP261 in March 2016. The aim was to try to ensure that there was a reconciliation of the TNUoS charges paid by GB Generators during the charging year 2015/16 with the statutory cap. Any amount in

[43] [A15].
[44] [A16].

excess of the €2.50/MWh cap could then be paid back via a negative generator residual[45] adjustment (in effect a credit) levied on all GB Generators who paid TNUoS during the relevant period if necessary. CMP261 therefore proposed a modification to allow a 'mid-year'[46] tariff modification to enable a reconciliation payment in Spring 2016. That would have avoided the need for an *ex post facto* assessment to be made of the nature and extent of the overpayment over two different charging years (where the over-payer and the recipient of a repayment might not be the same entity). Urgency was requested. A CUSC Panel meeting was urgently convened on 9 March 2016. A timetable was prepared by the CUSC Code Administrator that could have achieved this timeline.[47] But the request for urgent treatment of the modification proposal was rejected by GEMA on 17 March 2016.[48]

37. The subsequent CMP process was lengthy, involving consultations with all relevant parties. In summary:

    37.1. GEMA received the original Final Modification Report ('FMR') for CMP261 on 30 November 2016 from the CUSC Panel.

    37.2. GEMA then issued a 'send-back' letter to the CUSC Panel on 22 February 2017,[49] setting out its decision to direct that the CMP261 FMR be revised and resubmitted, mainly because of concerns about the distribution of the envisaged repayment of over-paid TNUoS charges.

    37.3. Following the send-back letter, the CMP261 Workgroup revised the FMR and it was re-submitted by the CUSC Panel to GEMA for decision on 23 June 2017,[50] adopting the "narrow interpretation" of the ITC Regulation in line with CMP224 and proposing a mechanism by which compliance with the statutory cap could be restored and maintained.

38. By its Decision of 16 November 2017, GEMA rejected CMP261. GEMA determined that there had not been a breach of the €2.50/MWh upper limit on average annual transmission charges paid by GB Generators, according to the ITC Regulation, in charging year 2015/16.

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[45] That is, a negative "transmission generation residual" charge ('TGR') which would *de facto* amount to a rebate to the Generators of the overpaid sums to NGESO.
[46] The term 'mid year' is used within, for example, the CMP261 FMR. It denotes that a change to transmission tariffs can occur at any point within the charging year (rather than what might be thought as just the mid-point of the charging year).
[47] [A17].
[48] [A18].
[49] [A19].
[50] [A8].

GEMA concluded that the implementation of the modification proposal would not better facilitate the achievement of the Applicable CUSC Objectives, and would not be consistent with its principal objective of exercising its functions in a way that protects the interests of existing and future Consumers. GEMA reasoned that it had two interpretations of the Connection Exclusion before it:

"• **'narrow interpretation**' - only those charges classed in the Connection and Use of System Code ('**CUSC'**) as "connection charges" are within the connection exclusion.

• **'broad interpretation**' - connection charges and most, if not all, "local charges" are within the connection exclusion (see 'the nature of the underlying asset funded by the charge' below for details)."

39. GEMA adopted the latter, broad interpretation.

(6) The appeal by EDF and SSE against the CMP261 Decision

40. EDF and SSE filed a notice of appeal seeking permission from the CMA to appeal against the CMP261 Decision on 6 December 2017. Permission was granted on 19 December 2017. On 10 January 2018, NGESO was granted permission to participate in the appeal as an intervener. Hearings before the CMA took place on 18 January 2018 and on 8 and 9 February 2018.

(7) The CMA's Decision in the CMP261 Appeal

41. The CMA published its decision in the EDF and SSE appeal on 26 February 2018. The appeal was dismissed. The CMA made the following findings of law and/or evaluations of the evidence before it:
    41.1. At [3.7] to [3.12] it described the development of the Offshore generation infrastructure, which was owned by Offshore Transmission Owners ('OFTOs') and which linked one or more windfarms to the onshore network. The physical assets consisting of an offshore local substation and a subsea cable connecting to an onshore local substation were described by the parties as an Offshore Generation Only Spur ('Offshore GOS').
    41.2. At [3.20] to [3.23], the CMA described the differences between transmission charges and Connection Charges under the terms of the CUSC.

41.3. At [3.25] to [3.28], the CMA described the cost-reflective Local Charges applied to Generators located onshore and offshore respectively under the CUSC. At [3.29] to [3.30] it analysed wider Locational Charges and at [3.31] it summarised the TGR i.e. the residual charge.

41.4. At [3.33] to [3.34], relying on evidence submitted by GEMA, the CMA explored the correlations between the network architecture in the relevant electricity transmission networks and the charges payable under the CUSC.

41.5. The CMA at [3.35] to [3.39] set out a description given by GEMA of the differences between 'deep' and 'shallow' connection boundaries within the transmission network.

42. Having set out the findings GEMA made in its CMP261 Decision at [4.30] to [4.46] and the Grounds of Appeal at [4.47], the CMA drew the following conclusions in relation to each of the Grounds raised.

43. <u>Ground 1</u> challenged GEMA's construction of the Connection Exclusion and its application to assets included in TNUoS charges under the CUSC. The CMA considered the Appellants' case primarily by reference to the treatment of charges for Offshore GOS. The proper interpretation of the Connection Exclusion as applied to Offshore GOS was central for the determination of the appeal. [5.75] In relation to Ground 1, the CMA found:

43.1. The approach to the interpretation of EU law provisions was common ground: [5.76].

43.2. The recovery of the cost of Offshore GOS through TNUoS charges was permitted under the EU regime. [5.81] But the Connection Exclusion had to be given an autonomous EU law construction, rather than simply taking its lead from the domestic treatment of the charges: [5.82]-[5.83].

43.3. Offshore GOS assets have the same characteristics as connection assets, in that they are also required for connecting a specific Generator to the transmission system: [5.85].

43.4. For the purposes of the Connection Exclusion, a distinction had to be drawn between those assets required by individual Generators for connection to the system, and those assets deployed in the transmission network for the purposes other than being required for connection to the system. That distinction did not depend on the basis for charging for the use or connection of the asset under the CUSC: [5.87]. The Connection Exclusion should not therefore be determined by reference to the GB charging structure.

43.5. No definition of "the system" to which connection was to be made under the ITC Regulation and the framework of electricity Regulations and Directives did not assist. The matter was therefore considered as one of principle: [5.90]-[5.93].

43.6. At [5.94], the CMA stated as follows:

> "It seems to us that 'the system' here must mean the system as it exists at the point that a new Generator wishes to be connected to it. Any assets that are then required by that new Generator for connection to that pre-existing system (such as Offshore GOS in the case of a new windfarm) are ones that fall within the Connection Exclusion, and such assets continue to be required by that Generator for connection to the pre-existing system even once the Generator is operational. We therefore accept GEMA's submission that connecting equipment continues after the initial act of connecting to be 'required for connection to the system'."

43.7. The CMA rejected the Appellants' contention that once a Generator had connected to the network, further charges related to the act of transmission, rather than the act of connection. The Offshore GOS used for the act of connection would continue to be required for connection to the system and the charges would therefore continue to be charges falling within the Connection Exclusion: [5.95].

43.8. The CMA also rejected the Appellants' criticisms of the 'but for' test applied by GEMA. [5.98] The ITC Regulation presupposed that a transmission system was in existence to which a Generator would need to be connected. GEMA's position that the system should be confined to that faced by a Generator at the time it wished to connect did not risk putting almost all the charges into the Connection Exclusion. On the facts as found by the CMA, the GOS did not represent a new segment of a transmission system. Rather the GOS assets were constructed because they were required for connecting a Generator to the pre-existing transmission system.

43.9. The CMA did not consider it necessary to opine on hypothetical situations beyond the GOS as it stood in 2015/16: [5.99].

43.10. A 'but for' test, construed as a 'required for' test, was consistent with the wording of the Connection Exclusion. Since the GOS were constructed for the purpose of connecting the relevant generation assets to the pre-existing transmission system, they fell within it: [5.101].

43.11. The CMA then considered whether or not an examination of the *travaux préparatoires* behind the ITC Regulation called for a different conclusion to be reached. It found that it did not: [5.112]. In particular, it did not consider that the background material showed that Connection Charges were limited to 'one-off' charges or that charges for the cost of connection assets could not be levied over time: [5.111].

44. Ground 2 challenged GEMA's factual appraisal of the charges which should be within the Connection Exclusion and, in particular, the nature and extent of the charges levied in relation to GOS. The Appellants contended that the relevant CUSC charges had been levied for the use of the transmission network. In relation to that contention, GEMA agreed that the "GB transmission system was defined domestically as the NETS": [6.13], but contended that the label attached under domestic arrangements was immaterial to the proper construction of EU legislation. The CMA found that:

44.1. The question was framed as one of fact, but in reality much turned on the issue of how charges should be categorised, which was one of law. The distinctions drawn in the CUSC between connection and usage charges could not simply be applied to the analysis under the ITC Regulation: [6.22]. While there were some similarities between the way in which Connection Charges and Local Usage charges for Offshore GOS were levied, both sets of charges recovered the cost of assets required for connection.

44.2. GEMA had been right to use the 'required for' test to determine whether Offshore GOS fell within the scope of the Connection Exclusion. Charges for Offshore GOS were therefore included in that Connection Exclusion: [6.23]. The Connection Exclusion had an autonomous EU law meaning: [6.24].

45. Ground 3 raised an allegation of abuse of process and/or infringement of the principle of regulatory consistency in the change of position adopted by GEMA between CMP224 and CMP261. The CMA made the following findings in rejecting this Ground:

45.1. The argument based on abuse of process would only succeed if GEMA had made a definitive decision about the scope of the Connection Exclusion in CMP224. GEMA had not reached a concluded view: [7.21]-[7.22].

45.2. GEMA had identified the competing constructions and had highlighted the risk of a legal challenge if it were to direct the implementation of a WACM based on the broad interpretation of the Connection Exclusion. It did not therefore need to form a concluded view, because the narrower construction would be less likely to lead to a breach of the statutory cap and so would meet the objective of compliance with relevant EU law: [7.27]-[7.29].

45.3. GEMA had not taken a 'binding' decision in CMP224 on the scope of the Connection Exclusion: [7.30].

45.4. As part of its observations *obiter* at [7.33], the CMA also found that the interpretation of the Connection Exclusion is a matter of EU law, not policy, and there is one legally correct interpretation. GEMA would have been obliged to uphold the CMP261 Proposal if NGESO's charges had breached EU law: [7.39].

46. <u>Ground 4</u> contended that the CMP261 Decision breached a number of applicable, general principles of EU law, including legal certainty, proportionality, non-discrimination and effectiveness. The CMA found that Ground 4 was premised in part on a conclusion that there had been a breach of the statutory cap set by the ITC Regulation (Ground 1); and in part on a conclusion that CMP224 contained a definitive ruling on the Connection Exclusion (Ground 3). Since neither premise was correct, Ground 4 fell away: [8.26]-[8.27].

47. There is no appeal mechanism against a decision of the CMA under the EA 2004 procedure. No judicial review was sought by EDF or SSE of the CMA's decision.

<u>D. PROCEDURAL BACKGROUND FOR CMP317, CMP327 AND CMP339</u>

<u>*(1) The Targeted Charging Review and Significant Code Review*</u>

48. GEMA formally launched a Targeted Charging Review ('TCR') in August 2017 as part of a wider Significant Code Review ('SCR') process, which encompassed a wider analysis of the residual and 'embedded benefits' associated with transmission charging in GB. A series of consultation exercises, workshops and other information gathering exercises were conducted. The TCR also examined how residual network charges were set and recovered, as well as reviewing a range of 'embedded benefits'. One of the aims was to remove distortions which had arisen between the exemption of Small Distributed Generators from the regime for transmission charging, which meant that when the TGR became negative (in order to avoid the breach of the statutory range set by the ITC Regulation), those smaller

Embedded Generators did not get the benefit of the credit or payment from the negative TGR. GEMA was keen to reduce harmful distortions arising from the transmission charging structure.

49. GEMA's decision on the TCR was published on 21 November 2019 ('the TCR Decision').[51] It revealed a change in approach to the overall direction of transmission charging. At p. 8, the TCR Decision stated:

> " ... we have decided to levy residual charges on final demand users, making residual charges simpler and more transparent, and have decided to implement a refined version of a fixed charge for the collection of residual network charges. We have decided that these reforms should be implemented in stages, which will help to mitigate the distributional impacts, with reforms to transmission charges being introduced in 2021 and distribution charges in 2022."

50. The TCR Decision also decided that action was needed to address the issue of 'embedded benefits.' In terms of a formal Direction under the SCR, GEMA proposed to direct that the TGR charges should be set to £zero. This was, however, expressly stated to be subject to ensuring compliance with the ITC Regulation. It also decided that Suppliers would no longer be able to reduce their liability for Balancing Services charges by contracting with small Distributed Generators (an 'embedded benefit').

51. GEMA issued its Direction to NGESO on 21 November 2019.[52] Paragraph 45 of the Direction stated:

> "The Proposal(s) must set out proposals to modify the Use of System Charging Methodology, Section 14 of CUSC to set the TGR to £0, subject to ensuring ongoing compliance with EU Regulation No 838/2010 (in particular, the requirement that average transmission charges paid by producers in each Member State must be within prescribed ranges – which for Ireland, Great Britain and Northern Ireland is 0 to 2.50 EUR/MWh). This should be achieved by charging generators all applicable charges (having factored in the correct interpretation of the connection exclusion as set out in EU Regulation 838/2010), and adjusted if needed to ensure compliance with the 0 to 2.50 EUR/MWh range."

[51] See [A20]: Somewhat confusingly, GEMA refers to this as the 'SCR Decision' in the contested Decision of 17 December 2020, and to the ITC Regulation as 'the Limiting Regulation' even though the nomenclature 'ITC Regulation' has been used by the Secretary of State for Business, Energy and Industrial Strategy in delegated legislation. The term 'Limiting Regulation' appears to be based on the proposed changes in terminology for the CUSC proposed in CMP339 (see Section D6 below).
[52] [A21].

52. The need for a potential adjustment mechanism to ensure compliance with the ITC Regulation was reiterated in paragraph 46 of the Direction, which stated:

"NGESO must work in conjunction with the relevant industry workgroup(s) in place for CMP317 (and provide such input as appropriate) to seek to ensure that any impact on that modification proposal by the TCR Decision is addressed in a manner that does not undermine NGESO's ability to comply with its obligations under this Direction. In doing so, the Proposal(s) must set out proposals for an appropriate adjustment charge to ensure compliance with the EU Regulation 838/2010, if NGESO considers it necessary (see paragraphs 4.76 to 4.78 of the TCR Decision)."

53. The correct interpretation of the Connection Exclusion was not spelled out in the Direction, but the Direction required NGESO to comply with the overall approach found in the TCR Decision, which the Direction intended to implement: see [51] of the Direction. The TCR Decision referred at [4.76] to [4.78] to the need for any modification proposals to give effect to the CMA Decision in EDF and SSE v. GEMA (*supra*). It recognised that the correct interpretation and application of the Connection Exclusion, when set beside a requirement to set the TGR to zero, might well necessitate an "appropriate adjustment charge" to ensure compliance with the ITC Regulation. At [4.79], GEMA gave its view that the CUSC was compliant with the ITC Regulation except for its treatment of the Connection Exclusion, construed in accordance with the CMA Decision. In that regard, it stated:

"We think that generators should face transmission charges for:

- off-shore local charges
- on-shore local charges (less those that fall within the 'Connection Exclusion'), and
- wider locational charges.

For compliance with the EU Regulation 838/2010 we expect these annual average transmission charges paid by producers to *[sic]* not to exceed €2.50/MWh or fall below €0/MWh. We accept that an 'adjustment charge' may be necessary to rectify this."

54. GEMA accordingly expected NGESO to include Local Charges (save those on-shore Local Charges falling within the Connection Exclusion) to be included in the definition of transmission charges for the purposes of assessing compliance with the ITC Regulation. It recognised that an adjustment mechanism for transmission charging for Generators might be needed, once the TGR mechanism could no longer be used for this purpose.

(2) The Original Proposal from NGESO in CMP317

55. Following the commencement of the TCR but before the publication of GEMA's final decision on that review, in May 2019 NGESO raised CMP317 entitled "*Identification and exclusion of Assets Required for Connection when setting Generator Transmission Network Use of System (TNUoS) charges*". The Proposal indicated that it was advanced as a means of updating the CUSC Calculation to reflect the correct legal interpretation of the Connection Exclusion, in the light of the CMA's ruling and ongoing debate about the boundary between assets used for connection to an existing transmission network and assets which properly formed part of that existing transmission network.

56. As summarised at p. 2 of the contested Decision, the Original Proposal had the following key features:

"• All Local Charges for Local Circuits and Local Substations paid by generators shall be excluded for the purposes of assessing compliance with the €0-2.50/MWh range;
• No target within that range shall be set – instead an error margin will be incorporated and where total Wider TNUoS revenues fall outside of the permitted range, an adjustment mechanism will be used solely to bring charges into that range;
• Neither BSC Charges nor any element of BSUoS Charges will be taken into account when assessing compliance with the range;
• These changes will be implemented on 1 April 2021 and will not be subject to any phasing."

(3) The Original Proposal from NGESO in CMP327

57. Following the publication of the TCR Decision on 21 November 2019, CMP327 was raised by NGESO as an Urgent Proposal for a modification, intended to give direct effect to GEMA's Direction that the TGR residual charge should be set to £zero in the operation of the CUSC charging procedures.

58. Given the evident overlap with CMP317, NGESO also requested that CMP317 be treated as urgent and requested for CMP327 to be amalgamated with CMP317. The CUSC Panel agreed that the matters were urgent and supported the amalgamation of CMP317 and CMP327 and their development on an urgent timetable, subject to GEMA's approval.

(4) The joinder of CMP317 and CMP327

59. On 29 January 2020, Ofgem gave permission for modifications proposed by CMP317 and CMP327 to be amalgamated. GEMA stated that "we have come to the conclusion that the [two] Proposals are sufficiently proximate to justify amalgamation on the grounds of efficiency and are logically dependent on each other. On that basis we have decided to grant consent to amalgamate the Proposals."[53] Nonetheless, on 7 February 2020 GEMA rejected NGESO's request for urgency.[54]

60. As summarised in page 7 of the contested Decision, the combined CMP317/327 Proposal raised the following issues for consideration by the CUSC Workgroup Panel:

"The CMP317/327 amalgamated modification proposal seeks to:
- Identify the charges paid by generators which fall within the Connection Exclusion, with due regard to the findings of the CMA Decision, and to ensure that such charges are excluded from the CUSC Calculation;
- Set the TGR to £0 as directed by the Authority, subject to compliance with the Limiting Regulation; and
- Raise new proposals as regards the treatment of BSC Charges and certain BSUoS Charges (related to congestion management) and whether those charges should be included within the CUSC Calculation."

(5) The CUSC Workgroup and Panel procedure in CMP317/327

61. The Workgroup met 18 times between 8 July 2019 and 4 June 2020. During this time, 83 Workgroup Alternative CUSC Modification proposals ('WACMs') were drafted by various Workgroup members. A consultation exercise commenced on 20 February 2020. The consultation closed on 12 March 2020, with responses received from 23 entities.

62. These various proposals were discussed within the Workgroup on various occasions and put to a Workgroup vote at a meeting on 9 June 2020. The Workgroup carried out two votes.[55] First, the majority of Workgroup members agreed that 44 of the 84 potential options were better than the existing provisions of the CUSC (the 'Baseline'). The Original Proposal was not one of the 44 that received a majority of the Workgroup vote. Secondly the Workgroup also voted by a majority that 62 of the 83 WACMs were better than the Original Proposal. However, the Workgroup did not come to a majority consensus on

[53] [A22].
[54] [A22].
[55] See pages 46-55 of [A23].

which option was the best. Nonetheless, the most popular option, WACM72, received support as 'best' from four out of 15 Workgroup members.[56] The next most popular option was WACM79 with two votes. The Workgroup Report was presented to the CUSC Panel meeting on 26 June 2020 who agreed that the Workgroup had completed their terms of reference and that the Code Administrator consultation for CMP317/327[57] could thus proceed.

63. At the CUSC Panel meeting on 31 July 2020, the CUSC Panel considered all the modifications (consisting of the Original Proposal and 83 WACMs[58]) and the responses[59] to the Code Administrator consultation. A majority of the Panel recommended the modifications identified in the table set out at p. 9 of the contested Decision to be better than the Baseline (i.e. the existing provisions in the CUSC) in facilitating the Applicable CUSC Objectives ('ACOs'). The Panel did not recommend by majority that the Original Proposal was better than the Baseline. The Panel vote (for all 84 options) as to whether each was better than the Baseline is shown as Vote 1 on pages 66-68[60] of the CMP317/327 Final Modification Report ('the CMP317/327 FMR'). The Panel did not reach an overall majority consensus as to the 'best' overall option. It was not formally required so to do. The 'best' overall option, whilst a 'custom and practice' of some duration, is provided to GEMA as additional information and is separate from the requirement for the CUSC Modifications Panel Recommendation Vote[61] to be included in the FMR to GEMA.

64. The CMP317/327 FMR was published on 13 August 2020. It set out the respective thoughts of the CUSC Panel members on the various issues raised by CMP317/327. It summarised the responses[62] to the two industry consultations of the proposed changes. It also summarised the results of the CUSC Panel voting process[63] on the Original Proposals and

[56] A further vote was received for WACM73, which differs from WACM72 only in the level of the target for average Generator transmission charging which is set, raising it from €0/MWh to €0.25/MWh.
[57] [A24].
[58] There were 83 WACMs in the case of CMP317/327 and 23 in the case of CMP339, considered below.
[59] These are contained in Annex 19 to the CMP317/327 FMR.
[60] For ease, those of the 84 options that received majority support from the Panel in the Panel Recommendation Vote are highlighted in yellow on pages 66-68.
[61] This is defined, in section 11 of the CUSC, as "the vote of Panel Members undertaken by the Panel Chairman in accordance with Paragraph 8.23.4 as to whether in their view they believe each CUSC Modification Proposal, or Workgroup Alternative CUSC Modification would better facilitate achievement of the Applicable CUSC Objective(s) and so should be made."
[62] The complete responses were also contained in the Annexes to the CMP317/327 FMR.
[63] The complete CUSC Panel voting is also contained in the Annexes to the CMP317/327 FMR.

each of the 83 WACMs. The CMP317/327 FMR also attached a large volume of material by way of Annexes, including the Legal Text associated with the Original Proposal at Annex 2.

(6) The Original Proposal in CMP339

65. On 12 March 2020, NGESO raised CMP339 as a consequential modification to incorporate new definitions into Section 11 of the CUSC to support the proposals being developed under CMP317/327. CMP339 was progressed alongside CMP317/327 as part of a Joint Workgroup, but there was no formal approval by GEMA for it to be amalgamated with the existing procedure.

66. The CMP339 legal text provided a range of definitions required to support implementation of the various proposals under CMP317/327. Overall, there were 13 new defined terms proposed by the Workgroup. For some terms, multiple options were put forward for the definition.[64] Of the 13 definitions, four were included in every CMP339 option, as they were necessary for each proposed solution in CMP317/327. These definitions are:

> "• 'Limiting Regulation': 'European Commission Regulation 838/2010 in the context of setting limits on annual average transmission charges payable by Generators (or any subsequent UK law specifying such limits).'
> • 'Adjustment Revenue': 'A positive or negative adjustment to overall Generator TNUoS charges to ensure compliance with the Limiting Regulation.'
> • 'Adjustment Tariff': 'The non locational £/kW tariff that applies Adjustment Revenue to Generators liable for TNUoS charges to ensure compliance with the Limiting Regulation.'
> • 'Ex-Post Reconciliation': 'The charge or credit to Demand and Generator Users in respect of TNUoS charges in the event of a breach of the Limiting Regulation'."

67. These four terms were approved by GEMA when it accepted the Original Proposal in CMP339, as further outlined below. In addition, the CMP339 FMR also included a definition of 'Relevant BSC Charges' at [4.7], namely:

> "The sum of the main funding share element of the Annual BSC Charges forecast to be paid by Transmission connected Generators in the relevant Charging Year as per Section D of and defined in the Balancing and Settlement Code."

[64] As GEMA's decision in CMP339 ([A25]) records at p. 2, the terms and definitions are listed in Sections 4.2 – 4.8 of the CMP339 FMR.

68. A Workgroup was established in April 2020. It voted on the Original Proposal on 16 June 2020. The resultant Workgroup Report was presented to the CUSC Panel on 26 June 2020. There was a Code Administrator consultation exercise which commenced on 30 June 2020. At the CUSC Panel meeting on 31 July 2020 the Panel voted on CMP339 against the Applicable CUSC Standard Objectives. The CUSC Panel recommended by majority that the Original and all WACMs 1- 23 better facilitated the Applicable CUSC Objectives than the Baseline. The FMR for CMP339, which sets out the salient details of the steps taken above, was issued on 13 August 2020.[65]

(7) The contested Decision in CMP317/327

69. GEMA published the contested Decision on 17 December 2020.[66] It set out GEMA's approval of the Original Proposal in CMP317/327. Part of that proposal aimed to implement GEMA's Direction that the TGR should be set to £zero, subject to compliance with the ITC Regulation. As set out above, SSE raises no objection to that aspect of the contested Decision in principle. However, in addition, the contested Decision approved the following aspects of the Original Proposal which SSE does seek to challenge:
    69.1. All Local Charges for Local Circuits and local substations paid by Generators shall be excluded for the purposes of assessing compliance with the €0.00-2.50/MWh range set by the ITC Regulation.
    69.2. No target within that range shall be set. Instead, an error margin will be incorporated and where total Wider TNUoS revenues fall outside of the permitted range, an adjustment mechanism will be used solely to bring charges into that range.
    69.3. Neither the relevant BSC Charges nor any element of BSUoS Charges will be taken into account when assessing compliance with the range.
    69.4. These changes will be implemented on 1 April 2021 and will not be subject to any phasing.

70. Notwithstanding the approval of the Original Proposal, and its blanket exclusion of all Local Charges from inclusion in the calculation of transmission charges for the purposes

[65] [A26].
[66] [A27].

of the ITC Regulation, the contested Decision nonetheless recognised that this approach was, in itself, flawed. The contested Decision disagreed with NGESO's contention that any charges associated with system architecture other than forming part of the MITS would represent Local Charges and be within the Connection Exclusion. Instead, GEMA indicated that it "expected" NGESO to:

> ". . . bring forward a further CUSC Modification Proposal (in sufficient time to enable the modifications to be effective as of 1 April 2022) to
>
> • Further update the CUSC charging methodology so as to include, in the assessment of compliance with the range, Local Charges in respect of Local Assets (i.e. local substations and Local Circuits) to the extent that such assets were pre- existing at the time the generator paying those charges wished to connect to the National Electricity System ('NETS'); and
>
> • Remove from the calculation determining compliance with the range the TNUoS Charges payable by 'Large Distributed Generators' and their associated volumes (MWh)."

71. GEMA also added (at p. 2) that:

> "We also expect NGESO to examine whether there has been historic non-compliance with the Limiting Regulation and, if so, to bring forward one or more additional CUSC Modification Proposals to address this."

72. The decision of GEMA to set the TGR to £zero necessarily meant that the mechanism which had historically been used to prevent annual average transmission charges exceeding the statutory range set in the ITC Regulation was no longer to be available to NGESO in the implementation of CUSC charging. It was therefore necessary for GEMA to consider the Original Proposal in CMP317/327 and the 83 WACMs and determine:

72.1. The correct construction of the Connection Exclusion as a matter of law;

72.2. The best means of avoiding the imminent breach of the statutory range set by the ITC Regulation.

73. As to the <u>first issue</u>, GEMA concluded (at p. 10) that none of the 84 proposals incorporated the correct interpretation of the Connection Exclusion. It nonetheless considered that the Original Proposal would be likely to avoid the imminent risk of a breach of the ITC Regulation posed by the *status quo*. It also concluded that the Original Proposal would better facilitate the achievement of the ACOs than either the *status quo* or any of the 83 WACMs. GEMA determined that approval of the Original Proposal was "consistent with

our principal objective and statutory duties." It accordingly approved the Original Proposal and directed that the necessary changes to the CUSC be made.

74. Notwithstanding that conclusion, GEMA also stated at p. 10 that:

> "Our approval of the Original Proposal is on the express basis that it is a 'stop-gap' measure which should avert an imminent risk of breach of the Limiting Regulation, and allow time for the formulation of a longer-term solution that properly reflects the correct interpretation of the Connection Exclusion. We expect NGESO to bring forward a further CUSC Modification Proposal that will fully give effect to the correct interpretation of the Connection Exclusion."

75. GEMA expanded on its view of the correct interpretation of the Connection Exclusion at p. 18 and in Legal Annex Two. At p. 18, GEMA stated that:

> "In summary, we consider that the Connection Exclusion includes all charges paid by generators in respect of Local Assets (whether shared / shareable or otherwise) that were required to connect the generator(s) in question to the NETS as the NETS existed at the time the generator(s) wished to connect. We consider that charges paid by generators in relation to Local Assets which existed at the point at which such generator(s) wished to connect to the NETS do not fall within the Connection Exclusion."

76. GEMA developed a stylised example to explain the outcome of its conclusions on a series of sets of hypothetical facts. At p. 19, GEMA also confirmed that while the Original Proposal had treated <u>all</u> Local Charges as being within the Connection Exclusion, on GEMA's interpretation that would not be the case for "Local Assets which existed at the point at which the Generator paying the charge wished to connect to the NETS." The Original Proposal was therefore necessarily "over-inclusive" in its approach (p. 20). Rather than sending the matter back to the CUSC Panel for the reformulation[67] of a compliant solution, GEMA nonetheless added:

> "Neither the existing provisions of the CUSC Calculation nor any of the proposals in the FMR reflect this interpretation. The Authority therefore needs to choose between the imperfect status quo and a series of imperfect alternatives. It is open to the Authority to approve a modification proposal which is based on an incorrect interpretation of the Connection Exclusion, if that proposal is better than the (imperfect) Baseline and the other (imperfect) proposals at facilitating the achievement of the ACOs."

[67] As, for example, GEMA had done with CMP261 on 22 February 2017 ([A19]). See paragraph [37] above.

77. As to the second issue, GEMA recognised that there was a "serious and imminent risk" of a breach of the ITC Regulation through the TGR becoming so deeply negative that the lower limit of the range (€0.00/MWh) would be breached. The reason for this was that the high volume of Offshore Local Charges had been incurred, which the CUSC treated as not being within the Connection Exclusion. Since treating those charges as related to transmission would push the transmission charges beyond the upper limit (€2.50/MWh) of the statutory range, the corresponding adjustment which would have to be made to the TGR would then take the average charge paid by Generators below the floor of €0.00/MWh (i.e. all Generators would, on average, be given a transmission credit[68]). It follows from this, however, that the erroneous inclusion of such charges within the Connection Exclusion would *ceteris paribus* lead to a likely breach of the upper limit.

78. GEMA also made the following determinations on the basis of the italicised issues below:

78.1. *Specific BSC Charges*: Specific elements of certain BSC Charges were not to be included in the calculation of annual average transmission charges when assessing whether the statutory range had been breached, since "as a matter of EU law," those specific BSC Charges fell within the Ancillary Services Exclusion found in the ITC Regulation (p. 12).

78.2. *BSUoS Charges relating to Congestion Management*: while these BUSoS charges were excluded from the definition of an ancillary service in Regulation (EU) 2019/943 ('the Recast Electricity Regulation')[69] they nonetheless still fell within the scope of the Ancillary Services Exclusion (p. 13). They were not therefore to be included in the CUSC calculation for the purposes of the ITC Regulation. Further legal reasoning was provided in Legal Annex One of the contested Decision.

78.3. *Phasing of the implementation*: GEMA declined to allow the changes to be brought in over a phased implementation period of two or three years (p. 14).

78.4. *Introduction of a target to aim for a lower annual average transmission charge than €2.50 MWh*. GEMA rejected the proposals for setting a target annual average transmission charge to facilitate a downward trend in the level of transmission costs imposed on Generators. GEMA considered that the inclusion of an error margin within

[68] Historically (and continuing today) it has only been Generators located in southern Britain who have received a transmission credit – that is they are paid (rather than pay for) for their use of the GB transmission system.
[69] Regulation (EU) No 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), OJ [2019] L No 158, 14.6.2019, p. 54.

the CUSC Calculation gave sufficient protection against the risk of a breach of the ITC Regulation (p. 17).

79. The Appellants analyse GEMA's reasoning in more detail when developing the grounds of appeal in Section F below.

(8) The decision of GEMA in CMP339

80. While CMP339 was not formally joined with CMP317/327, the final Decision of GEMA in CMP339 makes clear that it follows the approach adopted in the amalgamated CMP317/327. By a decision also dated 17 December 2020, GEMA approved the Original Proposal in CMP339.[70] In doing so, it stated that:

> "We are approving the Original Proposal for CMP339 because it is the corresponding solution to the Original Proposal under CMP317/327. The Original Proposal for CMP339 will add the necessary definitions to the CUSC for the Original Proposal of CMP317/327 to be effectively implemented.
>
> The definitions required to implement our decision on CMP317/327 are the four universal definitions listed above,[71] and the specific definition of 'Charges for Physical Assets Required for Connection' which supports our decision in CMP317/327. The definition of 'Charges for Physical Assets Required for Connection' which enables implementation of the Original Proposal for CMP317/327 is 'Connection Charges and charges in respect of an Onshore local circuit, Onshore local substation, Offshore local circuit and Offshore local substation.'

81. As indicated above, SSE challenges this CMP339 decision to the extent that it adopts and gives effect to the contested Decision in CMP317/327.

E. RELEVANT LEGAL FRAMEWORK

(1) UK domestic provisions

82. Section 4(4) of the Electricity Act 1989 ('EA 1989') defines transmission and transmission system as follows:

[70] [A28].
[71] See Section D6 above.

"'transmission', in relation to electricity, means transmission by means of a transmission system;
'transmission system' means a system which—
(a) consists (wholly or mainly) of high voltage lines and electrical plant, and
(b) is used for conveying electricity from a generating station to a substation, from one generating station to another or from one substation to another."

83. Section 3A(1) EA 1989 states:

"The principal objective of the Secretary of State and the Gas and Electricity Markets Authority (in this Act referred to as 'the Authority') in carrying out their respective functions under this Part is to protect the interests of [existing and future] consumers in relation to electricity conveyed by distribution systems [or transmission systems]."

84. Section 3A(1B) requires GEMA to act in a way that is best calculated to further the principal objective, "wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors." Under section 3A(2)(b), GEMA must nonetheless have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part 1 EA 1989.

85. Section 3A(5A) provides that:

"(5A) In carrying out their respective functions under this Part in accordance with the preceding provisions of this section the Secretary of State and the Authority must each have regard to—
(a) the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed; and
(b) any other principles appearing to him or, as the case may be, it to represent the best regulatory practice."

86. Section 4 EA 1989 prohibits the unlicensed generation, transmission, distribution or supply of electricity. Section 6 empowers GEMA to grant one of six classes of licence, including generation licences. Section 7 empowers GEMA to set general conditions that will be applied to licensees under the licensing regime. Section 8A sets certain standard conditions identified by cross-reference to provisions found in section 33 of the Utilities Act 2000 and other provisions of the EA 2004. Sections 8A(2) and 11A confer on GEMA a power to modify the standard conditions.

(2) European Union legislation

87. Directive 2009/72/EC of the European Parliament and of the Council concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC[72] ('the Electricity Directive 2009') contained a number of provisions governing the conduct of national regulatory authorities, such as GEMA, in their domestic electricity generation and distribution markets. The general objectives of GEMA as the National Regulatory Authority ('NRA') at all material times were governed by Article 36 of the Electricity Directive 2009. Article 37 sets out the duties and powers of the NRAs. Article 37(6)(a) sets out the duties of the NRAs in respect of "…fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for … [(a)] connection and access to national networks, including transmission and distribution tariffs or their methodologies". Article 37(4)(a) of the Electricity Directive 2009 requires the UK as a Member State to ensure that GEMA as an NRA has a power "to issue binding decisions on electricity undertakings."

88. That Directive has now been replaced with a recast Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU ('the Recast Electricity Directive').[73] However, the due date for implementing this recast Directive is 31 December 2020. Since the UK is no longer a Member State of the European Union, it is the provisions of the Electricity Directive 2009 which will continue to inform the proper construction of EU retained law in this field, in accordance with the terms of the European Union (Withdrawal) Act 2018 ('EUWA 2018'), save where express reference is made in other legal instruments to the terms of the Recast Electricity Directive.

89. The ITC Regulation was adopted under Article 18 of Regulation (EC) No 714/2009 ('the Electricity Regulation 2009').[74] The Electricity Regulation 2009 aimed, by Article 1(1), to set fair rules for cross-border exchanges in electricity. Of particular relevance:

[72] OJ [2009] L No. 211, 14.08.2009, p. 55.
[73] OJ [2019] L No 158, 14.6.2019, p. 125.
[74] Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 ('the Electricity Regulation 2009'), OJ [2009] L No 211, 14.8.2009, p. 15.

89.1. Recital (11) recognised that TOs should be compensated for costs incurred as a result of hosting cross-border flows of electricity on their networks.

89.2. Recital (12) then noted that payments and receipts from compensation should be taken into account when setting national network tariffs.

89.3. Recital (13) confirmed that a degree of harmonisation is required in charges for cross-border access in order to avoid distortions to trade.

89.4. Recital (23) noted that the NRAs should ensure compliance with the rules contained in this Regulation and the Guidelines adopted pursuant thereto.

89.5. Article 8(7) required network codes to be developed for cross-border network and market integration issues, without prejudice to Member States' rights to establish national network codes which do not affect cross-border trade.

89.6. Article 14 required charges for access to networks to be transparent and to reflect the actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator. They had to be applied in a non-discriminatory manner. Article 14(3) required the charges for network access to take account of "actual payments made and received as well as payments expected for future periods of time, estimated on the basis of past periods."

89.7. Article 19 required the NRA to ensure compliance with this Regulation and with the Guidelines adopted pursuant to Article 18. By Article 18(2), those Guidelines may seek to achieve a measure of harmonisation in relation to national tariff systems for producers and Consumers.

90. The ITC Regulation was adopted under Article 18 of the Electricity Regulation 2009. In material part:

90.1. Recital (10) states that "Variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised."

90.2. Article 2 states that "charges applied by network operators for access to the transmission system shall be in accordance with guidelines set out in Part B of the Annex."

90.3. Part B contains the Guidelines for a Common Regulatory Approach to Transmission Charging ('the Binding Guidelines'), which are extracted below for completeness:

> "1. Annual average transmission charges paid by producers in each Member State shall be within the ranges set out in point 3.
>
> 2. Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a Member State.
>
> For the calculation set out at Point 3, **transmission charges shall exclude**:
> (1) **charges paid by producers for physical assets required for connection to the system or the upgrade of the connection**;
> (2) **charges paid by producers related to ancillary services**;
> (3) specific system loss charges paid by producers.
>
> 3. The value of the annual average transmission charges paid by producers shall be within a range of 0 to 0,5 EUR/MWh, except those applying in Denmark, Sweden, Finland, Romania Ireland, Great Britain and Northern Ireland.
>
> The value of the annual average transmission charges paid by producers in Denmark, Sweden and Finland shall be within a range of 0 to 1,2 EUR/MWh.
> **Annual average transmission charges paid by producers in Ireland, Great Britain and Northern Ireland shall be within a range of 0 to 2,5 EUR/MWh**, and in Romania within a range of 0 to 2,0 EUR/MWh.
>
> 4. The Agency shall monitor the appropriateness of the ranges of allowable transmission charges, taking particular account of their impact on the financing of transmission capacity needed for Member States to achieve their targets under the Directive 2009/28/EC of the European Parliament and of the Council and their impact on system users in general.
>
> 5. By 1 January 2014 the Agency shall provide its opinion to the Commission as to the appropriate range or ranges of charges for the period after 1 January 2015." [Emphasis added]

91. The Electricity Regulation 2009 was replaced by the Recast Electricity Regulation with effect from 1 January 2020 in accordance with its Article 71. In accordance with recitals (72) and (73) and pursuant to Article 58, the Commission retains a delegated power to adopt implementing or delegated acts. This power extends to the promulgation of network codes pursuant to Article 59 or Binding Guidelines under Article 61 in appropriate cases.

(3) Status of the ITC Regulation and Recast Electricity Regulation post-31 December 2020

92. Each of the ITC Regulation and the Recast Electricity Regulation is treated as retained, direct EU legislation following the end of the Implementation Period. Section 3(1) of EUWA 2018 states that direct EU legislation in force immediately prior to IP Completion Day (31 December 2020) remains in effect. This is necessarily subject to such amendments as the UK Legislature has made to give the overall regime an ongoing coherence in the light of the UK's departure from the EU.

93. In relation to the ITC Regulation, certain modest changes have been made by the Electricity Network Codes and Guidelines (Markets and Trading) (Amendment) (EU Exit) Regulations 2019, SI 2019 No 532 ('the Network Codes and Guidelines Regulations 2019'). Regulation 2 deals with interpretation. It defines 'the ITC Regulation' as "Commission Regulation (EU) No 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging." Regulation 3 establishes that the ITC Regulation is amended in accordance with the provisions in Schedule 1 to the Network Codes and Guidelines Regulations 2019. Schedule 1 provides *inter alia* for the following amendments to the ITC Regulation:

"In Part B of the Annex—
(a) in paragraph 1—
(i) for "each Member State" substitute "Great Britain and Northern Ireland";
(ii) for "ranges" substitute "range";
(b) in paragraph 2, for "a Member State" substitute "Great Britain and Northern Ireland";
(c) for paragraph 3 substitute—
"3 Average annual transmission charges paid by producers in Great Britain and Northern Ireland shall be within a range of 0 to 2.5 euros per megawatt hour."
(d) omit paragraphs 4 and 5."

94. The effect of these amendments on the relevant text of Part B of the Annex to the ITC Regulation is as follows:

"1. Annual average transmission charges paid by producers in Great Britain and Northern Ireland shall be within the range set out in point 3.

2. Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of Great Britain and Northern Ireland.

For the calculation set out at Point 3, transmission charges shall exclude:
(1) charges paid by producers for physical assets required for connection to the system or the upgrade of the connection;
(2) charges paid by producers related to ancillary services;
(3) specific system loss charges paid by producers.

3. Average annual transmission charges paid by producers in Great Britain and Northern Ireland shall be within a range of 0 to 2.5 euros per megawatt hour."

95. The Explanatory Memorandum to the Network Codes and Guidelines Regulations 2019 records that:

"These Regulations amend Commission Regulation (EU) No 838/2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, and Commission Regulation (EU) No 2017/2195 establishing a guideline on electricity balancing which form part of the domestic law of the United Kingdom on and after exit day by virtue of section 3 of the European Union (Withdrawal) Act 2018."

96. The Electricity and Gas etc (Amendment etc) (EU Exit) Regulations 2020, SI 2020 No 1016 thereafter by Regulation 5 further amended the text of the retained ITC Regulation so as to delete the reference to Northern Ireland in each provision.

97. The Electricity and Gas (Internal Markets and Network Codes) (Amendment etc.) (EU Exit) Regulations 2020, SI 2020 No 1006 ('the Amendment Regulations 2020') by Regulation 7 and Schedule 4 make some modest changes to the terms of the Recast Electricity Regulation. These changes are addressed further under Ground 3 in Section F below.

(4) Terms of the Transmission Licence

98. Condition C4 of NGESO's Transmission Licence sets out the basis for the charging provisions for TNUoS charges which NGESO shall adopt. Under this condition, NGESO:
    98.1. has to set a methodology which will be approved by GEMA.
    98.2. has to conform to the use of system charging methodology as modified in accordance with standard condition C5.
    98.3. As set out in C4(7) "References in paragraphs [C4]1, 2, 5 and 6 to charges do not include references to: (a) connection charges".

99. By Condition C5, NGESO must at all times keep the use of system charging methodology under review. Paragraph 2 of Condition C5 states (and paragraph 3 of Condition C6 dealing with Connection Charges is in similar terms):

> "The licensee shall, subject to standard condition C10 (Connection and Use of System Code (CUSC)) and in accordance with the relevant provisions of the CUSC, make such modifications of the use of system charging methodology as may be requisite for the purpose of better achieving the relevant objectives."

100. The relevant objectives are defined in paragraph 5 of Condition C5 as:

> "(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
>
> (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);
>
> (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;
>
> (d) compliance with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency; and
>
> (e) promoting efficiency in the implementation and administration of the system charging methodology."

101. Condition C6 of NGESO's Transmission Licence deals with the Connection Charging methodology. Paragraph 4 of C6 states:

> "The licensee shall … prepare a statement approved by the Authority of the connection charging methodology in relation to charges, including charges:
> (a) for the carrying out of works and the provision and installation of electrical lines or electrical plant or meters for the purposes of connection (at entry or exit points) to the national electricity transmission system;
> (b) in respect of extension or reinforcement of the national electricity transmission system rendered (at the discretion of a transmission licensee where the extension or reinforcement is of that licensee's transmission system) necessary or appropriate by virtue of the licensee providing connection to or use of system to any person seeking connection;

(c) in circumstances where the electrical lines or electrical plant to be installed are (at the discretion of a transmission licensee where the electrical lines or electrical plant which are to be installed will form part of that licensee's transmission system) of greater size than that required for use of system by the person seeking connection;
(d) for maintenance and repair (including any capitalised charge) required of electrical lines or electrical plant or meters provided or installed for making a connection to the national electricity transmission system; and
(e) for disconnection from the national electricity transmission system and the removal of electrical plant, electrical lines and meters following disconnection,
and the statement referred to in this paragraph shall be in such form and in such detail as shall be necessary to enable any person to determine that the charges to which he would become liable for the provision of such services are in accordance with such statement."

102. Paragraph 7 of Condition C6 states:

"Unless otherwise determined by the Authority, the licensee shall only enter into a bilateral agreement or a construction agreement which secures that the connection charges will conform with the statement of the connection charging methodology last furnished under paragraphs 4 or 10 either: (a) before it enters into the arrangements; or (b) before the charges in question from time to time fall to be made."

103. In respect of the historical situation, it should be noted that Paragraph 8 of Condition C6 states:

"The connection charging methodology shall make provision for connection charges for those items referred to in paragraph 4 to be set at a level for connections made after 30 March 1990 which will enable the licensee to recover:
(a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any works, the extension or reinforcement of the national electricity transmission system or the provision and installation, maintenance and repair or (as the case may be) removal following disconnection of any electric lines, electric plant or meters; and
(b) a reasonable rate of return on the capital represented by such costs,
and for connections made before 30 March 1990 to the licensee's transmission system, the connection charging methodology for those items referred to in paragraph 4 shall as far as is reasonably practicable reflect the principles of sub-paragraphs (a) and (b)."

104. It should also be noted that compliance with various EU law obligations is to be secured, as confirmed by Condition 6A which states:

"Condition C6A: Connection charging requirements under the Electricity Directive
1. To the extent not already required under this licence, and for the avoidance of doubt:
(a) the licensee shall, as soon as reasonably practicable, publish the most recent statement of the connection charging methodology prepared under paragraph 4 or paragraph 10 of condition C6 (Connection charging methodology) ("the connection charging statement");

(b) the licensee shall obtain the Authority's approval to the connection charging statement before publication;
(c) the licensee shall conform to the published and approved connection charging statement."

105. In terms of Connection Charging objectives, in Condition C6 at paragraph 11(b) there is an additional item to add to the objectives itemised in Condition C5, namely "in addition, the objective, in so far as consistent with sub-paragraph (a), of facilitating competition in the <u>carrying out of works for connection to the national electricity transmission system</u>." [Emphasis added]

106. By Condition C5A(1) and Condition C6A(1) NGESO has to publish (i) a statement of its system of use charges (the TNUoS charges) and (ii) a statement of its Connection Charges (the Connection Charges). GEMA must approve both statements before publication. The relevant parts of Condition C7 state:

"1. In the provision of use of system or in the carrying out of works for the purpose of connection to the national electricity transmission system, the licensee shall not discriminate as between any persons or class or classes of persons.

2. Without prejudice to paragraph 1 and subject to paragraphs 3 and 5, the licensee shall apply charges objectively and without discrimination. The licensee shall not make charges for provision of use of system to any authorised electricity operator or class or classes of authorised electricity operator which differ in respect of any item separately identified in the statement referred to at paragraph 2(b) of standard condition C4 (Charges for use of system) from those for provision of similar items under use of system to any other authorised electricity operator or class or classes of authorised electricity operator except in so far as such differences reasonably reflect differences in the costs associated with such provision.
. . .
4. The licensee shall not in setting use of system charges restrict, distort or prevent competition in the generation, transmission, supply or distribution of electricity or in the participation of the operation of an interconnector."

107. Condition C9 addresses the functions of GEMA under the CUSC. Condition C9(6) states:

"Where the licensee is party to a relevant agreement for connection and/or use of system which is other than in conformity with the CUSC, if either the licensee or other party to such agreement for connection and/or use of system proposes to vary the contractual terms of such agreement in any manner provided for under such relevant agreement, the Authority may, at the request of the licensee or other party to such agreement, settle any dispute relating to such variation in such manner as appears to the Authority to be reasonable having (in so far as relevant) regard to the consideration that the terms so settled are, in so far as circumstances allow, similar to the equivalent terms in the CUSC."

108. Condition C9(8)(a) confers a similar power on GEMA where the relevant parties are in a dispute about the following matters:

"[whether] use of system charges made, or to be made, conform with the statement of the use of system charges furnished under paragraphs 2(b) or 8 of standard condition C4 (Charges for use of system), standard condition C4A (Charges for use of the licensee's transmission system) or standard condition C7 (Charges for Use of System) (as appropriate) which applied or applies in relation to the period in respect of which the dispute arise."

109. By Condition C10, NGESO is obliged to establish arrangements under the CUSC which facilitate the following objectives (these have been defined above as the ACOs):

"(a) the efficient discharge by the licensee of the obligations imposed upon it under the Act and by this licence;
(b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity; and
(c) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency,
(d) promoting efficiency in the implementation and administration of the CUSC arrangements,
and the licensee shall be taken to comply with this paragraph by modifying from time to time in accordance with the provisions of paragraphs 6 and 7 and the transition modification provisions, the document setting out the arrangements for connection and use of system which existed and which the licensee maintained pursuant to this licence immediately prior to the start of the transition period."

110. Condition C10(2) also requires NGESO to establish a Code Administrator and a CUSC Panel. The CUSC shall provide for the CUSC to be binding between NGESO and any CUSC user. Condition C10(6) establishes a procedure by which modifications can be made to the CUSC and the charging methodology. GEMA can impose modifications where these are necessary for compliance with the Electricity Regulation 2009 (now the Recast Electricity Regulation).

(5) The statutory Appeal framework

111. Section 173 EA 2004 sets out the framework for appeals against decisions by GEMA in respect of licence conditions. It states in material part:

"(1) An appeal from a decision by GEMA to which this section applies [shall lie to the Competition and Markets Authority (in this Chapter referred to as "the CMA")].

(2) This section applies to a decision by GEMA if—
(a) it is a decision relating to a document by reference to which provision is made by a condition of a gas or electricity licence;
(b) that document is designated for the purposes of this section by an order made by the Secretary of State;[75]
(c) the decision consists in the giving or refusal of a consent by virtue of which the document has effect, or would have had effect, for the purposes of the licence with modifications or as reissued; and
(d) the decision is not of a description of decisions for the time being excluded from the right of appeal under this section by an order made by the Secretary of State.
. . .
(3) An appeal against a decision may be brought under this section only by—
(a) a person whose interests are materially affected by it; or
(b) a body or association whose functions are or include representing persons in respect of interests of theirs that are so affected.

(4) The permission of the [CMA] is required for the bringing of an appeal under this section.

(5) The [CMA] may refuse permission only on one of the following grounds—
(a) that the appeal is brought for reasons that are trivial or vexatious;
(b) that the appeal has no reasonable prospect of success.
. . .
(9) In this section—
"consent" includes an approval or direction;
"gas or electricity licence" means a licence for the purposes of section 5 of the Gas Act 1986 (c. 44) or section 4 of the 1989 Act (prohibition on unlicensed activities)."

112. Section 175 EA 2004 sets out the grounds for the determination of the appeal by the CMA. The relevant parts state:

"(1) This section applies to every appeal brought under section 173 of this Act.

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

[75] The relevant Order is the Electricity and Gas Appeals (Designation and Exclusion) Order 2014, SI 2014/1293. By Article 3(b) of that Order, a designated document includes "the Connection and Use of System Code, being the document of that title required to be prepared pursuant to Standard Condition C10 of a transmission licence." Article 6 excludes from the statutory appeal procedure a decision under the CUSC which "consists in the giving of a consent to a majority recommendation of Panel Members in the Modification Report."

(a) in the carrying out of its principal objectives under [. . .] section 3A of the 1989 Act (principal objectives and general duties);
(b) in the performance of its duties under those sections; and
(c) in the performance of its duties under sections 4AB and 4A of that Act of 1986 and sections 3B and 3C of the 1989 Act (environmental and health and safety considerations).

(3) In determining the appeal the [CMA]—
(a) may have regard to any matter to which GEMA was not able to have regard in the case of the decision appealed against; but
(b) must not, in the exercise of that power, have regard to any matter to which GEMA would not have been entitled to have regard in that case had it had the opportunity of doing so.

(4) The [CMA] may allow the appeal only if it is satisfied that the decision appealed against was wrong on one or more of the following grounds—
(a) that GEMA failed properly to have regard to the matters mentioned in subsection (2);
(b) that GEMA failed properly to have regard to the purposes for which the relevant condition has effect;
(c) that GEMA failed to give the appropriate weight to one or more of those matters or purposes;
(d) that the decision was based, wholly or partly, on an error of fact;
(e) that the decision was wrong in law.

(5) Where the [CMA] does not allow the appeal, it must confirm the decision appealed against.

(6) Where it allows the appeal, it must do one or more of the following—
(a) quash the decision appealed against;
(b) remit the matter to GEMA for reconsideration and determination in accordance with the directions given by the [CMA];
(c) where it quashes the refusal of a consent, give directions to GEMA, and to such other persons as it considers appropriate, for securing that the relevant condition has effect as if the consent had been given.

(7) A person shall not be directed under subsection (6) to do anything that he would not have power to do apart from the direction.
. . .
(11) In this section—
"consent" includes an approval or direction; and
"the relevant condition", in relation to a decision, means the licence condition the provisions of which have effect by reference to the document to which the decision relates."

113. The CMA has published rules governing the conduct of Energy Act appeals in CC10.

F. GROUNDS OF APPEAL

114. The Appellants advance six grounds of appeal, each of which is predominantly based on errors of law or fact committed by GEMA in the contested Decision. In addition, Grounds 5 and 6 contend that GEMA failed to have proper regard to or give appropriate weight to one or more of the Applicable CUSC Objectives (i.e. the ACOs) and/or its statutory purposes more generally.

(1) The First Ground of Appeal: error of law and/or fact in relation to construction and/or application of the Connection Exclusion

115. SSE respectfully contends that GEMA's conclusions on the proper construction of the Connection Exclusion are vitiated by errors of law or based on errors of factual appraisal. They also fail to comply with the statutory objective of pursuing regulatory consistency and/or pursuing a proportionate and non-discriminatory charging structure. It will lead to an outcome whereby the annual average transmission charges paid by Generators will exceed the statutory range (£0.00-2.50/MWh) set by the ITC Regulation. SSE advances a number of discrete limbs under this Ground of Appeal:

115.1. The construction adopted by the Original Proposal which GEMA has approved fails to give an autonomous EU law meaning to the Connection Exclusion.

115.2. GEMA's construction fails to give a teleological interpretation of the Connection Exclusion in the light of the *travaux préparatoires* for the ITC Regulation.

115.3. As a matter of principle and in the light of the factual situation concerning the network architecture of the NETS, only GOS should be treated as 'connection assets' for the purposes of ensuring compliance with the statutory range, but no other Local Assets or Local Circuits should be. Alternatively, any Local Asset or Local Circuit which is shared by multiple users (including, but not limited to, meeting the needs of Demand) should be treated as a transmission network asset and not as a connection asset.

115.4. GEMA's favoured construction imposes disproportionate costs and operates in a discriminatory manner against GB Generators and in favour of Suppliers and/or the final Consumer as well as affecting cross-border trade and undermining the internal market.

115.5. GEMA's repeated iterations of the "correct" construction of the Connection Exclusion since 2010 fail to give legal and regulatory certainty. The goalposts should not be moved every time there is a threatened breach of the permissible range set by the ITC Regulation. GEMA has also failed to comply with the statutory requirement to act with regulatory consistency, since it has approved the Original Proposal which is contrary to GEMA's conclusions in the TCR Decision, and which NGESO was directed to follow when formulating its modifications to the CUSC.

(a) Failure to give an autonomous EU law meaning to the Connection Exclusion

116. The purposive or teleological approach to the interpretation of EU law is well established. It is necessary to consider the "spirit, the general scheme and the wording" of the relevant provisions: see Case 26/62 van Gend en Loos v Nederlandse Administratie de Belastingen [1963] ECR 1, CJEU at p. 13. The interpretation must place the provision "in its context" and be read "in the light of the provisions of Community law as a whole, regard being had to the objectives thereof and to its state of evolution at the date on which the provision in question is to be applied": Case 283/81 CILFIT v Ministero della Sanita [1982] ECR 3415, CJEU at [20]. The general approach to construction of a term of EU law is to consider its usual meaning in everyday language, while also taking into account the context in which it occurs and the purposes of the rules of which it is part: Case C-568/15 Zentrale zur Bekämpfung unlauteren Wettbewerbs Frankfurt am Main [2017] ECLI:EU:C:2017:154, at [19]. This was the approach followed by the CMA in the EDF and SSE decision at [5.76].[76]

117. The Original Proposal failed to follow these requirements. It adopted a definition of Connection Charges which deviated from the definitions given in the CUSC and the NGESO Transmission Licence. NGESO, as proposer of the Original Proposal, considered that the transmission system was the MITS, rather than the NETS. That was factually wrong as GEMA accepts in Legal Annex 2 at [7(a)] and [7(b)][77] of the contested Decision.

[76] Moreover, that method of construction will not change substantially now that the ITC Regulation has become retained, direct EU law pursuant to section 3 of EUWA 2018. The EUWA 2018 recognises that the existing approach to construction of EU law should still continue to apply: see section 6(3). In any event, the modern process of statutory construction involves not simply giving effect to the natural and ordinary meaning of the words used, but also to a consideration of the purpose behind the legislation. See R (Quintavelle and Pro Life alliance) v. Secretary of State for Health [2003] UKHL 13, [2003] 2 AC 687, per Lord Bingham at [10] and Lord Steyn at [21]; and UBS AG v. HMRC [2016] UKSC 13, [2016] 1 WLR 1005, SC per Lord Reed at [61]-[68].

[77] "In our view, "*the system*" should be interpreted as the NETS. Our reasons for this are as follows:

a. The most natural everyday meaning of *"the system"* is the entire transmission system (as it exists at the relevant time) of a member state. In the context of GB, this is the NETS. There is nothing in the wording of the Limiting Regulation to suggest that *"the system"* is intended to refer only to some subset of the transmission system.

Moreover, the Original Proposal applied the CUSC incorrectly, since it proposed to include all Local Charges on a blanket basis within the Connection Exclusion, even though both the internal CUSC framework and the NGESO Transmission Licence treated those charges as transmission charges, rather than Connection Charges. The CUSC has a separate section dealing with Connection Charges at Part 1 of Section 14 of the CUSC. The Original Proposal accordingly cherry-picked aspects of the existing CUSC, changed their internal treatment and then proposed to exclude transmission charges (by classifying them, for the purposes of the CUSC Calculation only, as Connection Charges) from the scope when calculating compliance with the ITC Regulation range.

118. GEMA has approved the Original Proposal without any modification. The contested Decision is accordingly flawed, not least since GEMA itself accepts that:

118.1. NETS is the relevant transmission network for consideration. It is not appropriate to treat MITS as the relevant network when assessing transmission charges.

118.2. It is not appropriate to treat all charges for use of Local Circuits and Local Assets (as defined in the CUSC) as 'Connection Charges' (for the purposes of the CUSC Calculation only) as well as those charges which are, correctly, defined as 'Connection Charges' according to the CUSC and in compliance with the Electricity Directive 2009, although this is what the Original Proposal does.

119. The contested Decision accordingly approves a proposal which GEMA itself recognises is flawed and is inconsistent with EU law.

120. As a matter of principle, charges associated with the use of Local Circuits and Local Network assets should be treated as charges associated with transmission on the NETS, rather than as Connection Charges. GEMA has wrongly determined as a matter of principle that Local Charges in relation to assets found within the NETS can be treated as charges for connection, through approving the Original Proposal. Since the Local Assets are clearly

b. The Connection Exclusion should be given a uniform interpretation across the EU. The MITS is a concept specific to GB – even if other member states have some concept of a core part of their transmission systems, we are not aware that they define that core in the same way as the MITS is defined. By contrast, while other member states may well not use the term "*NETS*", they all have national transmission systems, such that the concept described by the expression "*NETS*" is not GB-specific."

part of the NETS, not the MITS, GEMA's decision necessarily treats assets which make up part of the relevant transmission network as 'connection assets'. That is simply inconsistent with its acceptance that the NETS, not the MITS, is the relevant transmission network to consider.

121. It is no answer for GEMA to refer to its 'expectation' that NGESO will bring forward an appropriate proposal to rectify the position in due course. The approved Original Proposal fails to comply with the ITC Regulation since it fails to confine the Connection Exclusion to its proper limits. The Connection Exclusion only removes from the ambit of the calculation of annual average transmission charges paid by Generators those "charges paid by producers [*sc.* Generators] for physical assets required for connection to the system or the upgrade of the connection." Local assets which are intrinsic part of the relevant network are transmission assets, since they exist for the purpose of transmitting electricity to the 'backbone' MITS network. The Original Proposal adopts a blanket approach of treating <u>all</u> Local Assets as "connection assets", even though that approach is not in fact supported by GEMA.

<u>(b) GEMA's construction fails to give a teleological interpretation or take sufficiently into account the *travaux préparatoires* for the ITC Regulation</u>

122. The legislative intent behind an EU measure may be elucidated by reference to the *travaux préparatoires* which precede it: C-583/11 P <u>Inuit Tapiriit Kanatami and Others v Parliament and Council</u> [2013] ECLI:EU:C:2013:625, CJEU at [59]; and Case C-477/13 <u>Angerer</u> [2015] ECLI:EU:C:2015:239, CJEU at [33]. This is particularly helpful in cases of textual ambiguity: Case C-304/15 <u>Commission v. United Kingdom</u> [2016] ECLI:EU:C:2016:706, CJEU, per Advocate General Bobek at [39]-[45].

123. GEMA has erred in law in failing to construe the meaning and purpose of the ITC Regulation in accordance with its *travaux préparatoires* and the legislative or other measures which preceded it. In doing so, GEMA has adopted an interpretation of the Connection Exclusion which departs from the legislative intention. The proposed application of the Connection Exclusion to all Local Assets accordingly fails to give proper effect to the correct construction of the ITC Regulation.

124. An analysis of the *travaux préparatoires* and the legislative history demonstrates that Connection Charges were understood to relate to the "one-off" act of connection and therefore principally concerned charges for that initial connection. This is so even if some of those "one-off" charges might constitute items of capital expenditure which, in accordance with accounting principles, would be subject to depreciation and therefore amortised over many years. The fact that ongoing charges for the initial act of connection might arise (as the CMA held at [5.94]-[5.95]) does not mean that the 'act' of connecting to the network continues indefinitely. Once an asset initially used for (and paid for by Connection Charges) the act of connecting is used for the purposes of transmitting electricity by a network of multiple users (including, but not limited to, meeting the needs of Demand), it is a transmission asset. It stops being a 'connection' asset. The fact that the charges for the construction of the 'connection assets' may be payable over time does not vitiate this conclusion. A connection asset that, perhaps over time, becomes part of a shared transmission network that is used by more than the first connected Generator (including, but not limited to, meeting the needs of Demand) should thereafter be subject to charges for the use of the transmission system, in circumstances where Connection Charges for the cost of connection have properly been paid. Properly understood, the CMA Decision did not find to the contrary, since it was only dealing with Offshore GOS infrastructure, which on its factual findings, never became part of a formal transmission system. The CMA Decision declined to express a view at [5.99] on the issue which now arises in this appeal.

125. The historical genesis of the ITC Regulation is to be found in the guidelines developed by the European Regulators Group for Electricity and Gas ('ERGEG') at the instigation of the EU Commission in 2005 (the 'ERGEG Guidelines').[78] The ITC Regulation effectively put on a formal legislative basis the non-binding ERGEG Guidelines, which adopted the same €2.50/MWh cap for GB transmission charges. The ERGEG Guidelines also excluded from the scope of transmission charges the same three charge categories (i.e. charges for Connection, Ancillary Services and system losses).

126. In turn, the Commission in the ITC Regulation saw no reason to depart from the approach to tariff harmonisation in the ERGEG Guidelines, recognising the extensive consultation processes involved in their development.[79] It is therefore relevant to determine

[78] [A29].
[79] [A30], page 36 – 37.

how ERGEG developed the guidelines. In particular, in its response to a public consultation on those draft guidelines on 18 July 2005,[80] ERGEG stated that the €2.50/MWh cap "corresponds to the expected situation in the UK and Ireland (average charge for Generators) and allows for currency risk and present efforts to create an All-island electricity market from the Republic of Ireland and Northern Ireland markets."

(i) The ERGEG Guidelines

127. The ERGEG Guidelines were adopted in response to the legislative requirement set by Article 8(3) of the Regulation 1228/2003/EC on Cross Border Electricity Exchanges.[81] Article 4(2) of that Regulation stated that:

> "Producers and consumers ('load') may be charged for access to networks. The proportion of the total amount of the network charges borne by producers shall, subject to the need to provide appropriate and efficient locational signals, be lower than the proportion borne by consumers. Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals at European level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure. This shall not prevent Member States from providing locational signals within their territory or from applying mechanisms to ensure that network access charges borne by consumers ('load') are uniform throughout their territory."

128. The ERGEG guidelines of 18 July 2005 noted that transmission tariffs in Member States mostly reflect the requirements of Regulation 1228/2003 in that they were "by and large 'entry-exit' tariff systems rather than being distance based." They also noted that most Member States' tariffs fulfilled the criterion that "the majority of the charges fall on load rather than generation and that the major part of the electricity produced in the IEM is subject to a G charge regime which may put G at or very near zero." The Guidelines then added:[82]

> "As well as the fixed costs of the transmission network in the short run, i.e. capital and operation costs, transmission tariffs often include specific charges for losses, congestion and other ancillary services.
> Generators and consumers may also be required to pay a one-off charge for their initial connection to the grid usually called 'connection charge'. Charges related to losses, congestion and other ancillary services are also an important feature. These charges are not, however, considered to be part of the G charge for the purpose of these Guidelines."

[80] [A32], page 12.
[81] [A35].
[82] [A29].

129. In other words, the ERGEG Guidelines themselves drew a distinction between the initial (i.e. one-off) charge of connection to the transmission system and the subsequent transmission charges that a TSO would levy. Only the latter would be included in the calculation of the G Charge. The harmonising objective of setting G charges was explained in the following terms:

"To avoid distortions of competition, some harmonisation of the charges for access to networks of the generators, i.e. the 'G' charge is needed. Harmonisation of G charges, rather than L charges, is considered to be more important since the output from production facilities and the location of them is thought to be more responsive to price signals. However it should be emphasised that the 'G' charge is not the only charge a generator pays; connection charges have to be taken into account when making the investment decisions. The Member States also have different practises according to whether a generator is responsible for paying the costs connected to production related network components."

130. The final ERGEG Guidelines adopted the same approach as subsequently set by the ITC Regulation, calculating the G charge by summing the "annual total transmission tariff charges paid by generators" and dividing them by the "total measured energy injected annually by generators to the transmission network." (p. 34). The ERGEG Guidelines also stated:

"Annual average G shall exclude any **charges paid by generators for physical assets required for the generators connection to the system** (or the upgrade of the connection) as well as any charges paid by generators related to ancillary services or any specific network loss charges paid by generators." [Emphasis added]

131. The ERGEG Guidelines did not propose an exclusion for charges associated with "production related network components", despite the recognition from ERGEG that these were sometimes reflected in a separate charge to producers. Instead, ERGEG adopted the expression highlighted in bold in the citation in paragraph 130 above. ERGEG necessarily assessed the information regarding the charging situation in the UK and other Member States at the time. At that stage, the GB charging structure included Local Circuit charges in the calculation of transmission charges under CUSC.[83]

(ii) The EU Commission's adoption of the Binding Guidelines

[83] See *Graham 1* at [3.7] and [3.8].

132. The Commission subsequently consulted on its proposed approach to adopt Binding Guidelines on transmission charges.[84] It was recognised at p. 4 that ERGEG guidelines produced in 2005 had themselves been the subject of public consultation. But it noted that the main concern was on transmission charges borne by generation, where "the risk of distorting decisions is greatest." It observed that with the exception of Nordel areas, the UK and Ireland, ERGEG's draft guidelines set a narrow band in terms of costs per MWh.

133. The Commission subsequently issued a proposed Regulation establishing a mechanism, for the compensation of TSOs for the costs of hosting cross border flows of electricity and a common regulatory approach to transmission charging (which became the ITC Regulation). It was accompanied by the Commission's Impact Assessment ('CIA').[85] The CIA made clear that:

133.1. The Binding Guidelines would need to address the question of tariff harmonisation. The Guidelines formed part of the Third Energy Package, whose aim was to establish a single electricity market, by facilitating the cross-border supply of electricity (p. 5);

133.2. The fact that a transmission network represents a natural monopoly means that strict rules on pricing, overseen by the NRA, governing access and pricing of network use are necessary (p. 6-7);

133.3. Differential charges faced by Generators for using the transmission system can affect the effective functioning of the internal market (p. 7);

133.4. A key aspect of the regulatory regime is that non-discriminatory and transparent prices for network access should be approved in advance by NRAs (p. 7);

133.5. Tariff harmonisation was aimed at the charges for local system users for the "use of the transmission system." "Tariffs are paid to the TSO to whose system the user is connected." (p. 12) This implies strongly that the transmission charges are distinct from the Connection Charges paid in order to gain access to the transmission system in the first place. The costs allocated to the transmission system arise from costs allocated to the transmission of generated electricity (a cost to be allocated to generators); and from costs allocated to the consumption of electricity (a cost to be

[84] [A36].
[85] [A30].

allocated to Demand). This entails the G:D ratio found in the Guidelines, as what is not recovered from Generation (G) must be recovered from Demand (D). In order to achieve "neutrality between generators in different countries", a harmonisation procedure for the G:D ratio was needed;

133.6. The harmonisation of G Charges had been proposed in guidelines developed by ERGEG (p. 13). These draft guidelines already permitted a specific range of G Charges distinctly for Great Britain and Northern Ireland (as separate energy markets). In line with the approach recommended by ERGEG in the draft guidelines, the Commission focussed on the "absolute value of charges, rather than harmonising the basis on which costs are calculated and the proportion of costs allocated to Generators." This allowed local circumstances to be taken into account (p. 13);

133.7. The adoption of binding levels for G Charges in place of voluntary guidelines was considered appropriate. It was all part of a co-ordinated measure to compensate TSOs "in relation to costs they incur as a result of hosting cross-border flows of electricity on their network." (p. 14);

133.8. The ITC mechanism was designed with a number of specific objectives in mind, including that it should be "transparent and stable" such that it is capable of specification and of being understood (p. 15);

133.9. A case had not been made out for departing from the range of allowable G-Charges set by the ERGEG guidelines. (p. 36) The adoption of those guidelines by a formal legal measure would improve legal certainty. Beyond that, national regulators were best placed to set the appropriate level of transmission tariff for the systems which they oversee;

133.10. Charges could be for both the actual use of the transmission system and the costs of connecting to the system, with the latter being described as the "**the initial costs associated with connecting … to the network**" [emphasis added] (p. 51);

133.11. In terms of Connection Charges, "shallow charging" was often preferred by the regulatory authorities to "deep charging" because it reduced the risk of the initial connector to the system bearing an undue level of costs for the system as a whole, which would encourage free-riding of investments by subsequent connectors. Shallow charging meant "only costs which are **exclusively associated with the new connection**" should be charged as Connection Charges (p. 52). [Emphasis added] This would then suggest that the bulk of the network infrastructure costs incurred by a TSO should be recovered through transmission charges, rather than Connection Charges.

134. The Commission's Impact Assessment[86] found, following its December 2008 public consultation, that there was insufficient evidence to support the adoption of a different range of average annual G charges than those established by the ERGEG Guidelines in 2005. It therefore proposed the incorporation of the ERGEG Guidelines in a binding legal measure.[87]

135. It can be seen that the text of the ITC Regulation as adopted is virtually identical to the text contained in the ERGEG Guidelines:

	ERGEG Guidelines	**ITC Regulation**
Calculation of transmission charge	The value of the 'annual national average G' is annual total transmission tariff charges paid by generators divided by the total measured energy injected annually by generators to the transmission network.	Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a Member State.
Exclusions	Annual average G shall exclude any charges paid by generators for physical assets required for the generators connection to the system (or the upgrade of the connection) as well as any charges paid by generators related to ancillary services or any specific network loss charges paid by generators.	…transmission charges shall exclude: (1) charges paid by producers for physical assets required for connection to the system or the upgrade of the connection; (2) charges paid by producers related to ancillary services; (3) specific system loss charges paid by producers.
GB range	The value of the 'annual national average G' within Great Britain, Republic of Ireland and Northern Ireland will be at maximum 2.5 €/MWh.	Annual average transmission charges paid by producers in Ireland, Great Britain and Northern Ireland shall be within a range of 0 to 2,5 EUR/MWh.

[86] [A3].
[87] Which the Commission noted in the Impact Assessment conclusions, at page 37, had significant support (see [A30]).

136. Since the ITC Regulation was intended to give effect to the ERGEG Guidelines, the intended meaning behind those Guidelines is plainly relevant. For present purposes, that includes ERGEG's attempt to remove from inclusion in the G Charge those one-off costs associated with the connection of the generator to the transmission system in the first place.

(iii) Connection charges as "one-off" or "initial" charges for connection to the transmission system

137. The Explanatory Notes to ERGEG's Guidelines describe Connection Charges as "a one-off charge for their initial connection to the grid" (p. 2).[88] There is nothing to indicate that the Commission intended to give a drastically broader construction to the concept of "Connection Charges" when it excluded Connection Charges from the use of transmission charges covered by the ITC Regulation. Indeed, its decision formally to adopt the ERGEG Guidelines, in almost identical terms, strongly suggests that the Commission did not intend (having consulted stakeholders) to depart from ERGEG's approach. The Commission's position is clearly set out in Section 6.2 of CIA where it states:[89]

". . . there are good grounds for establishing a framework within which regulators exercise their powers. These are accepted by the regulators themselves, who, as discussed, drew up draft Guidelines in 2005 on allowable G-Charges.

Neither as part of the consultation process or in the work undertaken by the consultants engaged by the Commission was significant evidence put forward to indicate a need at this point to adopt a different range of allowable G-charges than those provided for in the 2005 draft guidelines. Given the potential for adverse outcomes either in terms of costs faced by consumers of electricity or the effectiveness of locational signals within Member States, it is therefore not appropriate at this stage to make such changes to the regulatory regimes prevailing in Member States. However, the views expressed by respondents to the consultation clearly indicate that this is worth keeping under review, and in particular whether the variations in G charges are having a detrimental impact on cross border trade.

A 'no EU level action' approach would in many respects have the same outcome as formally adopting the draft guidelines, as the policy environment would remain largely similar. However, uncertainty as to the evolution of transmission tarification across the internal market would continue. In this light it is important to note the consultation process indicated **widespread support for formally adopting the 2005 draft guidelines**. Moreover, when they were developed it was clearly envisaged that they would serve as the basis for binding guidelines under the Regulation.

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[88] [A29].
[89] [A30].

Adopting the 2005 draft guidelines would serve to increase the legal certainty for market participants. It would not adversely affect the ability of TSOs and regulators to include effective locational signals within their territory. It would thereby have a clear and positive impact upon the coherence of the rules governing the internal market in electricity, without undermining either the effectiveness or efficiency of the current regime where there is a wide degree of discretion for national regulators.

The alternative approach of focusing on the methodology underlying the calculation of tariffs potentially would ensure that generators were treated equivalently. However, the rules would necessarily be quite complicated – dealing with matters of regulatory policy such as cost of capital, detailed treatment of infrastructure costs, treatment of losses, congestion management etc. Inevitably much regulatory discretion which exists at a national level would end up being removed, and this could have significant adverse consequences, and go against the principle of subsidiarity. **This is particularly relevant when the desirable outcome of a level playing [field] in the internal market in electricity can be more simply achieved by focusing on "outputs" – that is the actual charges faced by generators – without restricting the discretion of national regulators**." [Emphasis added].

138. The purpose behind the statutory range was accordingly to ensure that high transmission charges imposed on Generators would not operate as an impediment to the cross-border trading of electricity. A degree of harmonisation was to be achieved through the establishment of a common approach to what constituted a transmission charge. The exclusions were narrowly defined by reference to the Connection Exclusion, the Ancillary Services Exclusion and specific system loss charges paid by Generators. In terms of the Connection Exclusion, this was intended to cover those charges incurred in relation to physical assets used for the act of connection. Charges associated with physical assets used for transmission were to come within the scope of transmission charges when calculating the annual average transmission charges paid by Generators for the purposes of ensuring compliance with the statutory range.

139. The Original Proposal does not follow this analysis. It wrongly places within the Connection Exclusion <u>all</u> charges associated with Local Assets, including Local Circuits and local substations. Those assets form part of the NETS transmission network and are network assets, not connection assets. GEMA's approval of the Original Proposal therefore incorrectly construes and/or applies EU law.

<u>(c) GEMA's construction is wrong in principle and/or based on errors in its factual appraisal</u>

140. As set out in *Graham 1* at [3.7] to [3.9], the network architecture of the NETS has historically been reflected in an equivalent separation between Connection Charges and local transmission charges under the CUSC. The Local Charges cover charges for the use of Local Circuits and local substations. These assets are distinct from the connection assets which a transmission owner ('TO') provides for the connection of a Generator to the NETS at the specific local substation in question. Connection Charges payable under the CUSC reflect the TO's entitlement to recover the costs associated with the act of connection. In contrast, charges associated with the use of Local Circuits and local substations should be shared, in principle, between the users of those assets. The users of those assets will typically include not only one or more Generators but also any Demand network users which also connect to and/or use for their consumption the Local Assets at the same network node.

141. The evidence from GEMA, which the CMA cited at [3.33] of its Decision, was that the TO owns both connection assets and Local Assets. The particular treatment of those assets under the CUSC at the time was set out at [3.34] of the CMA Decision. As a matter of principle, at [5.86] to [5.87], the CMA drew a distinction between the treatment of the different assets under the CUSC and the ITC Regulation respectively. The Connection Exclusion necessitated a distinction to be drawn between: (i) those assets required by an individual Generator[90] for connection to the transmission system; and (ii) those assets deployed in the transmission network for purposes (such as for the use of the transmission system or the connection of Demand / consumption) other than being required for connection of that individual Generator to the system.

142. GEMA should have found, in the light of the CMA ruling, that while GOS were connection assets since they represent radial spurs from the transmission system which only one Generator uses,[91] Local Circuits and local substations by their nature serve to link more than one local Generator or Demand (load) or both to the broader transmission network. This is the case even if a particular Generator is, in fact, the first entity to use a given circuit.

[90] Or two generators in a pre-determined partnership arrangement, falling short of shared use of an identified transmission network.
[91] Again, or two generators in a pre-determined partnership arrangement, falling short of shared use of an identified transmission network.

143. Imagine, for example, that Salisbury Plain is no longer needed for military use. NGESO accordingly rolls out a programme of developing Local Circuits and substations with a view to giving means of access to windfarm Generators and Demand, so that electricity can then be distributed on the individual distribution networks developed for new housing development projects. That Local Network architecture would be aimed at ensuring the effective transmission of generated electricity <u>and</u> the effective distribution of electricity. It would serve both Generation and Demand. The mere fact that a particular windfarm was the first Generator to join that Local Network (using connection assets for which Connection Charges are indisputably levied) should not mean that it was thereafter to be treated as paying for "connection" to the transmission system, even after say five other Generators and five housing estates have also started making use of the common infrastructure.

144. The focus should have been on whether or not a particular asset was required for transmitting electricity across a defined network or was required instead for connection. In part, this requires an analysis of whether or not an asset existed prior to the act of connection by a given Generator, as suggested in WACM14. That WACM defined pre-existing assets to include Local Circuits and local sub-stations that existed prior to connection as pre-existing assets and therefore as forming part of the transmission system prior to the act of connection by a given Generator. GEMA's response at p. 21 of the contested Decision is circular and wrong. It states that this definition of pre-existing assets is flawed "since at the moment of connection, the assets (or virtually all of the assets) required for connection will have been installed." That approaches matters the wrong way round. If all of the relevant assets had already been installed, then that confirms an existing transmission system is in place, to which a Generator will join through the act of connection. Those existing Local Assets are no more required for connection than the overall NETS (or MITS) is required for connection. It is the assets, in terms of electrical plant, electric lines and meters, which enable the *specific* connection to the NETS to be made which should be taken into account as connection assets.

145. Connection assets will, on that approach, include those GOS of the type found by the CMA to be connection assets, since on the factual findings made by the CMA, the radial cable link to a given Generator operated to transmit electricity from the specific Generator to the Local Network, rather than as a physical asset whose purpose is to carry electricity

transmitted by transmission system users (including, where appropriate, Demand). The CMA expressly did not address a situation where the nature of the offshore network was developing, so that the relevant offshore assets (cables, local substations, plant etc) were "a new segment of transmission system": see the CMA Decision at [5.98(b)]. Indeed, it declined to venture a view on whether or not the development of a fully functioning Local Circuit offshore serving multiple Generators who had previously been connected by individual GOS (through individual radial spurs attaching to a local substation onshore) would require such assets to be treated as transmission assets.

146. The nature of a "generator only spur" as being a radial spur is a highly relevant factor in how charges for the use of those assets should be categorised. The following definition of a GOS was provided in [2.2] and [2.3] of the CMP317/327 FMR:

"2.3.1 A 'Generator only spur' (GOS) was defined by Ofgem and noted by the CMA as an asset that is solely required for a specific generator concerned and therefore one that would fall within the physical assets for connection exclusion of the Limiting Regulation. This would apply equally to offshore assets and onshore assets essentially depending on whether an asset is shared or not. It was argued that if the assets were only required for the specific generator, then they should be classed as physical assets for connection for the purposes of the Limiting Regulation Connection Exclusion.

2.3.2 Similarly, if a Generator only spur became an asset used by more than one generator, or shared with demand, it would not be considered as a physical asset required for connection of that generator to the transmission system, and would cease to be regarded as a Generator only spur. It would therefore no longer be classed within the Connection Exclusion for the purposes of the Limiting Regulation." [Footnotes omitted]

147. If the local assets making up a Generator's local circuit charge were to include more than one route to the rest of the network by connecting to more than one MITS node, for example, then those local circuits would no longer be a "spur" for the purpose of defining a GOS. Such a local circuit design could act as a substitute for reinforcement of a part of the MITS, so its purpose would be more than simply the connection of the Generator. This is a scenario which will become increasingly relevant in the development of the new offshore grid: see *Graham 1* at [4.11].

148. The fact that either onshore or offshore Local Assets are shared between multiple users of the transmission network, which may include sharing with other Generators and/or

Demand, is also a highly relevant factor in how charges for the use of those assets should be categorised.[92] A GOS that is shared with a Demand user is no longer a 'generator only' spur. A GOS shared with multiple Generators is no longer used by a single Generator. If, for example, an extensive offshore circuit of cables, substations and plant is developed, which connects multiple Generators (and possibly local Demand as well, if the network encompasses a remote island such as Shetland), then such assets should not be treated as assets necessary to connect a specific Generator to the mainland network (be that network MITS or NETS). The relevant assets are subject to a shared use. The charging for the use of those assets should reflect that shared use. Treating each Generator as separately requiring all of those assets for connection would make no sense.

149. Nor is GEMA right in principle to consider that an asset which may have initially been required for connection to the transmission network retains that status for time immemorial, regardless of the developing network infrastructure of which, after connection, it forms part. In the Salisbury plain example, the first Generator to connect may be the one who initially uses a local substation that serves as a potential hub for future connections to local Demand from three different housing estates. Over time, as other Generators and Demand connect to that hub, reinforcement works may be needed and additional links between different sections of the surrounding circuit may be put in place for security of supply reasons. While the use of the Generator's specific connection assets will remain unchanged, and used solely by that Generator, its use of the Local Circuit assets and the local substation will change dramatically. It will not be the only Generator making use of those Local Assets. Its use will be shared. Moreover, the assets become transmission assets and are no longer assets required for connection to the network in the first place.

150. GOS as described in the factual findings of the CMA can therefore properly be treated as an asset required for connection (as the CMA found and which SSE naturally does not seek to impugn in this appeal). But other aspects of Local Circuits, whether offshore or

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92 The shared use of local assets is already being considered by Ofgem in the context of NGESO's Offshore Coordination Project, whose Offshore Connection Review was published in December 2020 as Annex 3 to the Phase 1 Final Report: https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project . In section 2 (p. 8), NGESO considered the need for greater coordination in the relevant treatment of offshore connections and also the need for a review of the conclusions reached in CMP192. The Report recognises that the establishment of a user commitment liability (a form of financial security) by CMP192 would not work so well when multiple users were connecting to the transmission networks through a local circuit and local Generator driven investments triggered an increase in the level of the security required from those Generators to reflect their increased work on the NETS necessitated by their multiple connections. In paragraph 5.11 of its Impact Assessment accompanying CMP192 (https://www.ofgem.gov.uk/sites/default/files/docs/2012/02/cmp-192_master_9.pdf), Ofgem also recognised that the magnitude of local works required for offshore island generation could be significant, with a portion of the works required for local Demand.

onshore, cannot simply be treated as connection assets in the same way. Indeed, GEMA recognised in the TCR Decision that offshore Local Charges should be treated as transmission costs and should not be subject to the Connection Exclusion. This implicitly recognised that the offshore Local Circuits should *not* be treated as connection assets, but should be analysed as network assets, since the charges reflecting their use were not within the Connection Exclusion. The Connection Exclusion should not other than by limited exception, include physical assets used for transmission on a shared basis by two or more users of a Local Circuit (whether offshore *or* onshore), since those assets are necessarily used for the transmission of electricity by Generators (and any local Demand users). Those shared assets are used for the movement of electricity from one part of the system to another, often (but not always[93]) across the 'backbone' network of the MITS, to where Demand is located (which is primarily on the distribution network).

151. SSE contends, in the alternative, that GEMA's construction is wrong in law, since it fails to draw relevant distinctions between the first use of a Local Asset to connect a Generator to the NETS and one or more subsequent network users (including, potentially, end Consumers in the form of Demand/load or other Generators) who necessarily will be making use of an established transmission asset for the purposes of using a pre-existing part of the NETS infrastructure (rather than requiring a new asset to be put in place). While GEMA has indicated that in principle it would sanction such an approach, that is not in fact an approach which is followed by approving the Original Proposal, which draws no such distinction.

152. There is also a clear flaw in using the MITS to determine the basis for charges falling within or outside the Connection Exclusion, as the Original Proposal does. This can be seen if the relevant facts considered by the CMA change substantially, as offshore networks (for example) develop. Imagine that two separate offshore Local Circuits develop so that two different sets of five windfarm generators (each on a separate local transmission network) and two Suppliers (one for each of the local transmission networks) connect at a Grid Supply Point on an island location such as Shetland. The Local Circuit assets will be subject to a shared use sufficient to meet the criteria for becoming part of the MITS network: see *Graham 1* at [3.2]. Imagine then that excess generation over and above that needed to meet

[93] It is possible that electricity produced by generators in one locality is predominantly, if not wholly, used by Demand in that same locality and thus whilst that electricity is transmitted across the NETS (to the distribution network) not all of that electricity (or, indeed, possibly any) is necessarily transmitted via the MITS.

the local Demand requirements is transmitted via a fixed HVDC cable link to the mainland network: see *Graham 1* at [4.11]. That link might also permit local Demand to be met from mainland electricity transmission where local Generation conditions do not produce enough electricity. The Grid Supply Point will be part of the MITS. The Original Proposal would not then treat the HVDC link as a connection asset. See *Graham 1* at [4.14]. If, however, only five windfarm generators on a single transmission Local Network connected, along with the two Suppliers, at a particular node on that Local Circuit and the HVDC link was fed from that node, then the node would not be treated as part of the MITS. The HVDC link would then be treated as a connection asset, rather than as a transmission asset, notwithstanding its shared used by five Generators and two Suppliers (at times of insufficient local generation) for the purposes of transmitting electricity to and from the mainland network.

(d) GEMA's favoured construction fails to comply with the principles of proportionality and non-discrimination

153. The outcome of GEMA's construction is that a far higher level of charges for the use of assets that transmit electricity are paid by Generators than would otherwise be the case. GEMA's approach accordingly favours Suppliers or the final Consumer or importers of electricity from outwith GB to a disproportionate extent. Its construction accordingly fails to comply with the following general principles of EU law which should have been respected by the contested Decision:

153.1. The principle of proportionality. The measures adopted must be appropriate to secure the attainment of the objective which they pursue and not go beyond what is necessary in order to attain it.[94]

153.2. The principle of equality and the interrelated requirement of non-discrimination.[95] This means that persons in like situations should not be treated differently without objective justification; and persons in different situations should not be treated in the same way.

[94] See Joined Cases C-1/90 and C-176/90 Aragonesa de Publicidad Exterior and Publivía [1991] ECR I-4151, CJEU at [16]; Joined Cases C-369/96 and C-376/96 Arblade and Others [1999] ECR I-8453, at [34] and [35]; and Case C-165/98 Mazzoleni v. Inter Surveillance Assistance SARL [2001] ECR I-2189, at [24]

[95] See Joined Cases 201 and 202/85 Klensch [1986] ECR 3477, CJEU at [9]-[11].

154. Recital (10) to the ITC Regulation made clear that a degree of harmonisation in the range of transmission charges should strengthen the internal market for electricity. The contested Decision has the effect of undermining that objective. It places a disproportionate burden of costs on GB Generators, in circumstances where interconnectors and therefore importers of electricity pay no such charges. The existence of an effective range on transmission charges paid by Generators in EU Member States means that GB Generation is competitively disadvantaged by the contested Decision. The scope for GB Generators supplying customers in EU Member States is diminished by the differential impact of the charging regime, as interpreted by GEMA. The opposite is also the case: the scope for Generators located in other EU Member States supplying customers in GB is enhanced by the differential impact of the charging regime that arises from the contested Decision.

155. Furthermore, Generators also pay a disproportionately higher share of transmission costs associated with Local Circuits and local substations than Suppliers, notwithstanding that Demand makes use of Local Assets when receiving electricity onto local distribution networks. This has a disproportionate impact on Generators, who will not be able to pass all or most of those additional costs on to the final Consumers for the reasons set out under Ground 4 below.

(e) Failure to comply with principles of legal certainty and regulatory consistency

156. In the Commission's Impact Assessment prior to adopting the ITC Regulation, the Commission recognised that the proposed Annex's Binding Guidelines could give rise to an incentive at a national level "to increase charges [to generators], and so provide a (short run) benefit to consumers" (p. 25).[96] However, as the Commission then explains, this would create "degree of legal and regulatory uncertainty, which has the potential to undermine [generator] investment decisions in the internal market" (p. 25). GEMA by its contested Decision has sought to advance a "short run" policy goal of avoiding a breach of the statutory range at the expense of the wider structural security for generation, as well as undermining the internal market, despite the Commission rightly resisting the temptation to do so.

[96] [A30].

157. There is also a breach of regulatory certainty occasioned by GEMA's repeated re-definitions (in, for example, CMP224, CMP261 and now CMP317/327) of the Connection Exclusion each time an impending breach of the range set by the ITC Regulation arises in GB. GEMA's evidence in the previous appeal before the CMA in EDF and SSE v. GEMA was that the Connection Exclusion did not extend to charging for Local Circuits and Local Assets found in the CUSC. GEMA's evidence was that connection assets stopped at the entry point to the local substation as, for example, is shown by the Ofgem diagram reproduced at paragraph 14 above. The CMA seemingly endorsed that approach (see [3.33]-[3.34] and [5.86]-[5.87] cited above), but declined to rule more widely than with regard to the proper classification of assets and use of assets on the GOS.

158. GEMA's contention in the CMP261 appeal was already a distinct evolution from its historic treatment of connection assets. In particular:

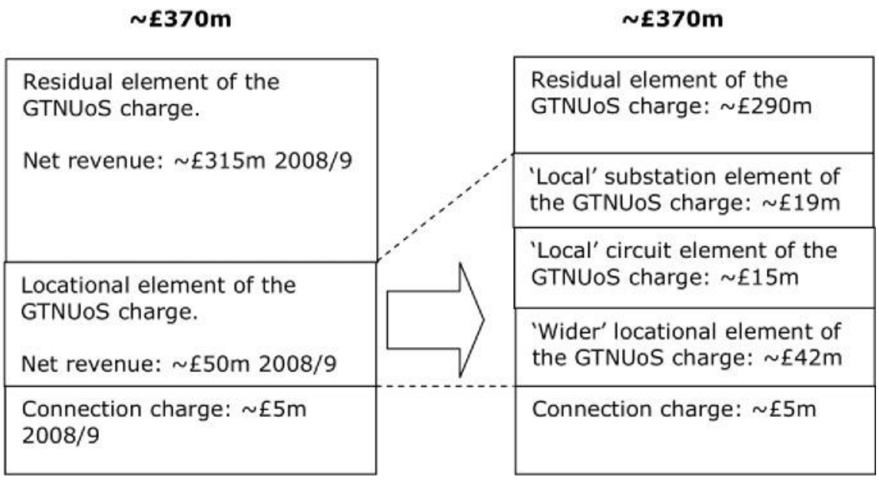
158.1. On 19 December 2003, GEMA issued its decision for Connection Charging Methodology Modification 07 ('CCM-M-07') entitled "Implementation of PLUGS - Change to Connection Boundary and associated removal of Land Charges and Type B Termination Charges and Change to Calculation of Site Specific Maintenance Charges".[97] By that decision, GEMA gave notice under section 49A EA 1989 that the amount NGESO could charge via Connection Charges would be reduced. In doing so, GEMA supported the inclusion of Local Circuit / GOS costs as transmission use of system charges.

158.2. During the autumn of 2004, GEMA considered a proposal from NGESO[98] on the charging methodologies for connection to, and use of, the relevant high voltage transmission system which concluded, in December 2004, with a formal decision.[99] In that Decision, GEMA set out its support for "shallow" Connection Charging. It explained that a "deeper" definition of connection assets "would be less effective in promoting competition" and that such methodologies could "result in transmission users being unduly or arbitrarily advantaged or disadvantaged based on when and where they connect to the network."[100]

[97] [A11].
[98] [A31].
[99] [A31].
[100] See [A31], paragraph 3.27.

158.3. In February 2005, GEMA published its own Impact Assessment in relation to the "Proposed Transmission Use of System Charging Methodology of the GB System Operator" (Document 25/05).[101] GEMA cited NGESO's contention that "recovering the costs associated with spur circuits through TNUoS rather than connection charges" would "result in greater consistency in treatment between users."

158.4. In December 2008, GEMA approved the separation of TNUoS in the TNUoS charging methodology into four components: (i) 'Local' circuit charges; (ii) 'Local' substation charges; (iii) 'wider' Locational Charges; and (iv) the Residual charge. Ofgem provided an illustration[102] of this change:



158.5. While this measure introduced a change to the transmission use of system charging boundary between local and wider transmission locational infrastructure assets, it did not alter the connection/transmission boundary.[103] Local and wider transmission assets remain within the TNUoS charging system and were not treated as "Connection Assets." In explaining the background to its decision, GEMA noted that the "Plugs" change in 2004 moved the transmission boundary from a "deep" to a "shallow" connection model. In doing so, it transferred "a substantial proportion of the costs associated with the cost of transmission infrastructure assets which are local to

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[101] [A33].

[102] From page 13, [A34].

[103] As was illustrated in the associated GEMA Impact Assessment and consultation document, dated 24 October 2008, in the diagram on page 13 (shown above) together with Figures 1 and 2 on page 46. ([A37]) Figure 1 refers to connection charges in terms of cost of assets required to connect an individual user and transmission charges in terms of cost of shared infrastructure. Figure 2 is reproduced above at paragraph 14. These diagrams were similar to those relied upon by Frances Warburton in her evidence before the CMA, as shown in [3.33] of the CMA Decision. See also *Graham 1* at [2.6]-[2.7] and [3.6].

generator connections from Connection Charges funded directly from users to TNUoS charges."[104] This was, of course, in keeping with the EU Commission's preference for shallow transmission charging, as set out above at paragraph 133.11. GEMA further explained that (prior to the change being decided upon) individual generators' TNUoS charges did not reflect their capital costs. This 2008 decision aimed to make the allocation of TNUoS costs fairer as between Generators, as opposed to adjusting the split between connection and TNUoS charges.

158.6. In addition, at the point at which the industry codes were applied to the new offshore transmission systems on 24 June 2009, the then applicable System Operator – Transmission Owner Code was modified by direction of the Secretary of State to enable the offshore regime to be introduced. As recorded by a Balancing Service Standing Group consultation paper prepared at around the same time,[105] the changes to the codes were designed to facilitate the introduction of competitively tendered transmission networks offshore, and also cater for the consequential treatment of any power station wishing to connect to the offshore transmission networks. The paper noted at p. 1 that:

> "At offshore 'Go-Live' through the direction of the Secretary of State, any asset operating at a voltage of 132kV will be required to be owned by a Transmission Licensee. Subsequently, all Power Stations connected offshore via sub-sea cables of 132kV or above will see their connection to the Transmission System move from an onshore connection point to the offshore point where the Power Station connects to the 132kV system. Offshore 'Go-Live' for the existing connected offshore Power Stations is expected to happen in 2011."

159. Accordingly, the GB Connection Boundary in place at the time of the ITC Regulation coming into effect included Local Circuit, local substation and GOS charges in the transmission use of system charging (not Connection Charging) structure. They had been charged by NGESO to the Appellants as part of the TNUoS charges. In its "2010 Great Britain and Northern Ireland National Reports to the European Commission in relation to Directives 2003/54/EC (Electricity) and 2003/55/EC (Gas)",[106] GEMA stated as follows:

"Network Tariffs - structure of charges

[104] [A38].
[105] [A39].
[106] [A40].

53. Transmission Network Use of System (TNUoS) charges have four component parts:

• **'Local' circuit charge**. A locationally varying element reflecting the cost of transmission infrastructure assets used by generators to connect to the Main Interconnected Transmission System (MITS). This charge is derived with reference to the incremental power flows along "local" infrastructure circuit assets between the generation node and the next MITS substation.

• **'Local' substation charge**. This charge relates to the unit costs of relevant design and type of local infrastructure substation assets which are required for each generation connection.

• **'Wider' locational charge**. A locationally varying element reflecting the zonal average long-run forward-looking costs of connecting an incremental (or decremental) Megawatt (MW) of generation or demand at a given point on the transmission network. This charge component will be calculated on the generic cost base for carrying unit power over unit distance.

• **Residual charge**. The locational elements of the TNUoS charge do not recover the total amount of revenue allowed to the companies. This is because the transmission network is not optimally sized (as assumed by the charging model), and because the network comprises "non-locational" assets, such as substations, that contribute to overall security. Hence, once the 'local' and 'wider' locational tariffs have been calculated, a non-locational correction factor – generally called a residual charge - is applied to the tariffs to ensure that 27% of total revenues is recovered from all generators and 73% from all demand customers.

54. Under the powers conferred by the Energy Act 2004, the Government has been developing its policy to establish a regulatory regime for offshore transmission. It has concluded that a non-exclusive, price-controlled approach was the most appropriate licensing and regulating model and that the current transmission licence and industry code arrangements, wherever possible, should be extended to offshore. National Grid Electricity Transmission plc (NGET) has been appointed as the system operator offshore designate.

55. In this designate role, NGET proposed a modification to incorporate offshore electricity transmission charging arrangements as part of an integrated regime following the commencement of the forthcoming regulatory regime for offshore transmission. On the 30th of March 2009, we [GEMA] published our decision not to veto NGET's proposals.

The key features of these proposals included:

• The extension of the concept of transmission 'local' and 'wider system' infrastructure assets, the costs of which are recovered under the TNUoS charging methodology.
• The extension of the application of existing principles in defining the boundary between 'local' and 'wider' infrastructure assets for the purposes of TNUoS charges.
• The majority of assets forming part of the offshore transmission network will be categorised as 'local' and recovered from the local circuit and local substation elements of the tariff. These will be derived using the same principles as under the onshore

arrangements whilst including the introduction of specific details necessary for calculating offshore tariffs.[107]

56. There are 20 charging zones for generation and 14 for demand. For 2009/10 the demand charge varies between £3.38/kW and £25.90/kW whereas the 'wider' locational generation charge varies between £-6.98/kW and £21.59/kW."

160. This makes clear that GEMA has consistently treated Local Charges as part of TNUoS charges, and not as connection assets outside of TNUoS - and that it has communicated its approach to the EU Commission. In summary, while there have been adjustments in the charging arrangements over time, there has been no fundamental shift as to where the Connection Boundary should be drawn in GB since ERGEG developed its Guidelines in 2005 or since the Commission brought forward the ITC Regulation in 2009-10 until GEMA's decision in CMP261. In CMP261, the CMA concluded that connection assets would include GOS, but at [5.99] expressly drew no definitive conclusions about Local Assets more generally.

161. GEMA has now, with its contested decision to approve the Original Proposal contained within CMP317/327, shifted its definitional goalposts once more (having previously redefined the boundaries from CMP 224 to CMP 261) to advance a case which goes beyond that previously put to the CMA. That has a deleterious effect on regulatory certainty and presents a chilling effect on future investment. As set out in *Tindal 1* at [7.2] to [7.9], GEMA's repeated re-drawing of the terms of the Connection Exclusion serves to increase uncertainty over the regulatory basis of costs which have to be assumed for the lifetime of a project. The consequence of that uncertainty is that investors in infrastructure projects, as well as would be participants in the Capacity Market or potential contracting parties for Contracts for Difference ('CfD') (in relation to renewable energy) will each increase their assessment of the degree of risk associated with their individual projects. Indeed, it was the identification of uncertain revenues and uncertain risks that prompted the move towards the CfD regime under the Energy Market Review. That will damage the ability of the UK to meet its renewables targets, as *Tindal* 1 notes at [7.28] to [7.40]. The regulatory uncertainty, and the commercial and economic uncertainty it engenders, yet further

[107] [Footnote 12 in the source document] "To include: (a) Local circuit expansion factors and local circuit security factors will be defined for each OFTO, b) The local substation tariff would be based on both assets located on each OFTO platform and the offshore platform itself, but will contain a discount to reflect the fact that the onshore substation tariff does not include civil costs, and c) The wider locational and residual tariffs are based on the existing calculation method."

undermines the competitive position of GB Generators in the pan-European electricity market. Generators based in EU Member States benefit from a more stable approach to charging for transmission costs.

162. Further or alternatively, GEMA's approach also infringes its statutory obligation to act with regulatory consistency. In its Direction dated 21 November 2019, GEMA directed NGESO to put forward CUSC modification proposals that gave effect not only to the requirement to set the TGR to zero, but also to comply with the other findings of the TCR Decision. As set out at paragraph 53 above, GEMA intended that the calculation of transmission charges for the purposes of applying the ITC Regulation and its statutory range should include off-shore Local Charges, without any qualification, and onshore Local Charges save for those falling within the Connection Exclusion. In particular, the TCR Decision at [4.79] (p. 124) concluded that:

"For the avoidance of doubt, we consider that the CUSC is compliant with EU Regulation 838/2010 except for the interpretation of the 'exclusion connection' which needs to have the correct interpretation, in accordance with the CMA appeal regarding CMP261. We think that generators should face **transmission charges** for:
- off-shore local charges,
- on-shore local charges (less those which fall into the 'Connection Exclusion'), and
- wider locational charges." [Emphasis added]

163. The Original Proposal includes <u>all</u> Local Charges (onshore and offshore) in the Connection Exclusion, without any exceptions. This is confirmed by the definition of 'Charges for Physical Assets Required for Connection" given in CMP339, which states that it covers "Connection Charges and charges in respect of an Onshore Local Circuit, Onshore local substation, Offshore Local Circuit and Offshore local substation." As such, GEMA has approved a Proposal which runs counter to its express findings in the TCR Decision.

<u>*(2) The Second Ground of Appeal: the contested Decision is vitiated by breaches of public law principles*</u>

164. GEMA's decision is vitiated by its recognition that the Original Proposal does not apply the correct interpretation of the 'Connection Exclusion' regardless of whether or not SSE's construction is the right one. The contested Decision is internally inconsistent and/or procedurally flawed. It consciously adopts a construction of the ITC Regulation which it

concedes is incorrect in order to meet the short-term expedient of avoiding an impending breach of the limits set by the ITC Regulation. That impending breach only arises because of the adjustment mechanism that GEMA had initially chosen to put in place (namely the TGR), combined with its Direction to set the TGR to £zero. The contested Decision is accordingly vitiated in public law terms as being motivated by an improper purpose of avoiding a breach of the ITC Regulation at all costs, rather than applying the legally correct definition and making appropriate adjustments other than through the TGR. Giving the correct construction of the Connection Exclusion would still have permitted the Adjustment Mechanism now found in CUSC condition 14.14.5. to be applied.

165. The Original Proposal was based on a contention that the relevant definition of the transmission system in GB was based on MITS (not NETS). Ofgem accepts that is wrong. The definition of 'Connection Exclusion' in the Original Proposal was functionally based on the treatment of <u>all</u> Local Charges as being charges for connection to the system. The reality of GEMA's position is that they have approved the Original Proposal which they necessarily accept applies the wrong legal definition for the Connection Exclusion, in order to avoid breaching the statutory range. That is not a proper basis upon which to reach a regulatory decision. It is illogical and procedurally improper for GEMA to approve a proposal that they know is wrong in law as a "stopgap" measure when there are other ways of avoiding the breach of the statutory range which would work (as, for example, SSE proposed in WACM14, or as Uniper proposed in WACM72).

166. It is an improper purpose for GEMA to seek to use its statutory powers to achieve a result which is not contemplated by the statutory provisions themselves. See <u>R (Palestinian Solidarity Campaign Ltd) v. Secretary of State for Housing, Communities and Local Government</u> [2020] UKSC 16, [2020] 1 WLR 1774, SC per Lord Wilson at [20]-[22]. It is a requirement of any CUSC modification that it should be a lawful implementation of domestic and EU law. Approving a CUSC modification which GEMA accepts wrongly construes EU law is not a lawful discharge of its statutory power. The use of unlawful means to achieve a desired outcome is improper: <u>Laker Airways Ltd v. Department of Trade</u> [1977] QB 643, CA per Lord Denning MR at pp. 705-706 and 708.

167. GEMA's purported justification for this approach is that it is entitled to balance the competing objectives set out in the ACOs and that approving the Original Proposal is the

lesser of two evils. It recognises at p. 10 that the Original Proposal "does not incorporate the correct interpretation of the Connection Exclusion. Notwithstanding this, we have concluded that the Original Proposal would be likely to avoid the imminent risk of a breach of the [ITC] Regulation that is posed by the status quo, and better facilitate achievement of the ACOs than either the status quo or any of the WACMs." GEMA sought to defend this position by noting that its approval was "on the express basis that it is a 'stop-gap' measure which should avert an imminent risk of breach of the [ITC] Regulation, and allow time for the formulation of a longer-term solution that properly reflects the correct interpretation of the Connection Exclusion." At p. 19, GEMA states that "it is open to the Authority to approve a modification proposal which is based on an incorrect interpretation of the Connection Exclusion, if that proposal is better than the (imperfect) Baseline and the other (imperfect) proposals at facilitating the achievement of the ACOs."

168. This is not a permissible approach under either EU or domestic law. The question is one of compliance with legal obligations derived from EU law and which are now maintained as a statutory legal requirement by domestic law. The rule of law requires observance of these principles. The CUSC obligation should merely reinforce it and give a contractual and regulatory means by which to compel the compliance of licensees with the relevant principles. GEMA cannot therefore excuse or waive such compliance as part of a balancing exercise in the evaluation of competing ACOs. In other words, GEMA should not tolerate the incorrect application of EU law requirements (as now retained in the domestic legal regime) because it is a better way of achieving some other specific CUSC objective. To cede primacy to the CUSC would be to denigrate the need to comply with mandatory rules of law.

169. In R (Goodman) v. London Borough of Lewisham [2003] EWCA Civ 140, [2003] Ev LR 644, CA at [8], Buxton LJ in dealing with the meaning of 'urban development projects' in a planning case observed that:

"These are very wide and to some extent obscure expressions, and a good deal of legitimate disagreement will be involved in applying them to the facts of any given case. That emboldened Lewisham to argue, and the judge to agree, that such a determination on the part of the local authority could only be challenged if it were Wednesbury unreasonable. I do not agree. However fact-sensitive such a determination may be, it is not simply a finding of fact, nor of discretionary judgment. Rather, it involves the application of the authority's understanding of the meaning in law of the expression used in the Regulation. If the authority reaches an understanding of those expressions that is wrong as a matter of law, then the court must correct that error: and in determining the meaning of the statutory expressions the concept of reasonable judgment as embodied in Wednesbury simply has no part to play."

170. Moreover, GEMA should have noted that it had already made clear that certain on-shore Local Charges and all off-shore Local Charges would necessarily be treated as 'transmission' charges (and not Connection Charges) for the purposes of the ITC Regulation, as set out at paragraph 162 above. There was no appeal brought by stakeholders against the TCR Decision, which was accordingly a binding decision made by GEMA. The Original Proposal failed to comply with this decision of GEMA and GEMA accordingly acted inconsistently and in a manner contrary to the statutory objectives in agreeing to it.

171. At p. 19 of the contested Decision, GEMA has unduly constrained its approach, and unlawfully fettered its discretion, by stating that it had to "choose between the imperfect status quo and a series of imperfect alternatives." That too is a breach of public law principles, since a decision maker cannot fetter its discretion by failing to take into account relevant matters: R v. Gaming Board of Great Britain *ex p* Kingsley (No 2) [1996] C.O.D. 241, per Jowitt J. One relevant matter was the power held by GEMA to send back the case to the CUSC Panel for more work. GEMA has an express power to accept a proposed modification to the CUSC, reject it or send it back to the CUSC Panel for further analysis and work (this send back situation is described in Condition 8.23.12[108] of Section 8 of the CUSC). GEMA used this power, for example, in the course of CMP261[109] when it was not clear that the options submitted to it remedied the breach (if it occurred).[110] GEMA failed to consider that send back option with the CMP317/327 FMR, notwithstanding the fact that a workable solution could have been found and that any impending breach of the ITC Regulation could have been addressed by a mid-year tariff change.

[108] "If the Authority determines that the CUSC Modification Report is such that the Authority cannot properly form an opinion on the CUSC Modification Proposal and any Workgroup Alternative CUSC Modification(s), or where the CUSC Modification Proposal and/or any Workgroup Alternative CUSC Modification(s) constitutes an EBGL Amendment where the Authority requires an amendment to CUSC Modification Proposal and/or any Workgroup Alternative CUSC Modification(s) in order to approve it, it may issue a direction to the CUSC Modifications Panel: (a) specifying the additional steps (including drafting or amending existing drafting associated with the CUSC Modification Proposal and any Workgroup Alternative CUSC Modification(s)), revision (including revision to the timetable), analysis or information that it requires in order to form such an opinion; and (b) requiring the CUSC Modification Report to be revised and to be resubmitted."
[109] [A19].
[110] "We have identified the following issues with the [CMP261] FMR… • if there has been a breach, it is not clear that the options submitted to us remedy it, i.e. that they reimburse the right users the right amount of the alleged overcharge." See *ibid* p. 1.

(3) The Third Ground of Appeal: error of law in relation to the construction of the Ancillary Services Exclusion

172. SSE's third ground of appeal is that GEMA's construction of the 'Ancillary Services Exclusion' and its corresponding treatment of: (i) the Relevant BSUoS Charges; and (ii) the Relevant BSC Charges is wrong in law.

(a) The treatment of the Relevant BSUoS Charges

173. As the CMP317/327 FMR rightly pointed out at [9.3.8], Congestion Management costs incurred by NGESO are recovered under a BSUoS Charge which is split approximately 50:50 between Generators and Suppliers. The Workgroup in the FMR raised the question of whether those Congestion Management charges paid by Generators by way of BSUoS Charges (i.e. the relevant BSUoS Charges) should be counted towards the annual average transmission charges paid by Generators for the purposes of the ITC Regulation or whether they fell within the Ancillary Services Exclusion. GEMA decided that the relevant BSUoS costs fell within the Ancillary Services Exclusion (at pp. 13-14 of the contested Decision), largely for the reasons set out in Legal Annex One to the contested Decision. GEMA noted that this was consistent with the approach taken under the CUSC to date.

174. GEMA considered that an option which mandated the inclusion of the relevant BSUoS Charges within the CUSC calculation was "negative against ACOs a), b), c), d) and e), by comparison with the baseline," adopting the same reasons given for rejecting the proposed inclusion of the relevant BSC Charges in the calculation (which is addressed under section F(3)(b) below). That approach was wrong in law. The matter was not one for evaluation by reference to the ACOs. It was a question of giving effect to the autonomous EU law definition of "ancillary services."

175. GEMA set outs its reasoning behind the construction of the term "ancillary services" in Legal Annex One to the contested Decision. Its two principal reasons were that: (i) there was no definition of 'ancillary services' provided in the ITC Regulation; and (ii) it preferred to apply a definition derived from the Electricity Regulation 2009 rather than a more specific definition given in the Recast Electricity Regulation. Both reasons are flawed and the construction GEMA has adopted is wrong in law.

176. First, GEMA contends at paragraph 3 and 7(a) of Legal Annex One that the ITC Regulation gave no express definition to "ancillary services" and the drafter could not have had in mind the 2019 definitions. Taking that statement at face value, it is a non-sequitur. If a definition is undefined, it leaves room for the EU legislature to clarify that definition in later legislation. But in any event, the term 'ancillary services' was necessarily defined in the ITC Regulation by reference to the Electricity Regulation 2009 and the Electricity Directive 2009 (a point which GEMA positively asserts in paragraph 7(a) of Legal Annex One). The ITC Regulation was made pursuant to Article 18 of the Electricity Regulation 2009. It necessarily had to be construed in conformity with its parent legislation, otherwise it would be *ultra vires*.[111] In addition, the recitals to the ITC Regulation confirm that it was in accordance with an opinion given by a committee established under Article 46 of the Electricity Directive 2009. The ITC Regulation was a product of the Third Energy Package.

177. Article 2(1) of the Electricity Regulation 2009 stated that, with the exception of "interconnector", which was specifically defined, the definitions given in the Electricity Directive 2009 would apply to the Regulation. The following definitions were given by the Electricity Directive 2009:

177.1. Article 2(3): 'transmission' means "the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply";

177.2. Article 2(4): 'transmission system operator' means "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity";

177.3. Article 2(17): 'ancillary service' means "a service necessary for the operation of a transmission or distribution system";

177.4. Article 9(1) then links the defined transmission system to the system owned by a transmission system operator, since it states: "each undertaking which owns a transmission system acts as a transmission system operator."

[111] See, by analogy, Case C-677/18 Amoena Ltd v. HMRC [2019] EU:C:2019:1142, CJEU at [29] and [37]-[38].

178. Secondly, GEMA contends that the Recast Electricity Regulation did not amend the ITC Regulation and cannot therefore have been intended to alter its meaning. That is also a non-sequitur. It is true that the Recast Electricity Regulation did not amend the ITC Regulation. But it does not follow that the Recast Electricity Regulation accepted implicitly that the ITC Regulation bore a meaning which was at odds with an express definition given in the Recast Electricity Regulation. The more logical inference is that the EU legislature saw no inconsistency between the parent legislation (now the Recast Electricity Regulation) and the delegated legislation adopted by the Commission (a position apparently adopted by the Commission in the Commission's Impact Assessment, considered below). There was accordingly no need to amend the ITC Regulation. Indeed, had the EU legislature taken GEMA's view of the meaning of 'ancillary service' in the ITC Regulation, it would have been obliged either to amend the ITC Regulation or to make it clear that the Recast Electricity Regulation was adopting a different definition from that to be applied to the ITC Regulation.

179. The ITC Regulation was made by the EU Commission under a delegated power conferred by the Electricity Regulation 2009. That Regulation has now been recast and subsumed within the Recast Electricity Regulation. The Recast Electricity Regulation, read in conjunction with the Recast Electricity Directive, makes clear that charges for the costs associated with network Congestion Management are part of the annual average transmission charges paid by generators and not charges for ancillary services associated with the operation of the transmission network when determining compliance with the ITC Regulation statutory range.

180. Article 2 of the Recast Electricity Regulation contains the following definitions.

180.1. Article 2(4) states:

> " 'congestion' means a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements which cannot accommodate those flows;"

180.2. Article 2(60) confirms that:

“ ‘ancillary service’ means ancillary service as defined in point (48) of Article 2 of Directive (EU) 2019/944.”

181. Article 2(48) of the Recast Electricity Directive states that ‘ancillary service’ means “a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, **but not including congestion management**.” [Emphasis added]

182. Article 18 of the Recast Electricity Regulation provides *inter alia* that:

“1. Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner. Those charges shall not include unrelated costs supporting unrelated policy objectives.

Without prejudice to Article 15(1) and (6) of Directive 2012/27/EU and the criteria in Annex XI to that Directive the method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level. The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response. Without prejudice to paragraph 3 of this Article, those charges shall not be distance-related.

2. Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.

3. Where appropriate, the level of the tariffs applied to producers or final customers, or both shall provide locational signals at Union level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure.”

183. Article 20(3) requires Member States to take steps towards ensuing “cost-efficient and market-based procurement of balancing and ancillary services.” Article 59(1) empowers the Commission to adopt a network code governing *inter alia* ‘ancillary services’.

184. The wider package of regulation in this sector accordingly sets out provisions regulating ancillary services and proceeds on the basis that the term 'ancillary services' does not encompass 'Congestion Management'. Since they were not 'ancillary services', congestion charges were therefore regarded as part of the core annual average transmission charges paid by generators (to which the statutory range applies). The alternative would be that Congestion Management services are in some sense an entirely unrelated service to transmission (which would manifestly not be the case).

185. This approach is also consistent with the Impact Assessment conducted by the Commission prior to the adoption of the Recast Electricity Regulation. The Commission's Impact Assessment[112] set out concerns that inconsistent transmission tariff structures were leading to barriers to the internal energy market. It specifically considered whether full harmonisation of the approach to charges for ancillary services would be beneficial.[113] The CIA recognised that:

> "4.3.2. Tariffs are charged on demand and/or production in order to recover the costs associated with building, maintaining and operating transmission and distribution infrastructure. They can be used merely as a cost recovery tool, but also as a means to incentivise investments and behaviours. They also have the potential to have distortionary effects . . . More specific requirements are provided for under the inter-transmission system operator compensation mechanism ('ITC') regulation. This regulation sets down limits on the average annual transmission charges that can be applied in each Member States to electricity producers. The regulation also required ACER to provide an opinion to the Commission regarding the appropriateness of the range of charges, which it did on 15th April 2014.
> . . .
> 4.3.3. Deficiencies of the current legislation
> As detailed above, a framework for transmission tariffs is provided for in the Electricity Directive, Electricity Regulation and in the ITC Regulation (Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, OJ L 250, 24.9.2010, p. 5–11). These all provide significant scope for national differences without a view on how any potential negative or distortionary impacts can be resolved. Further, the ACER recommendation has not been implemented into the ITC Regulation. The Evaluation Report points out that '*whilst the Third Package contains provision on transmission tariffs, their level and design still differ significantly between Member States. This has the potential to distort price signals.*'
> . . .
> 4.3.6. Subsidiarity
> Charges applied to generators in relation to their connection to, and use of, networks can be significant. Differences in these charges can therefore have an effect on decision

[112] [A41].
[113] See the CIA (*supra*) at [4.3.5].

making, whether it is on investment locations or on dispatch of energy, and can therefore add distortions into the market. Given the highly integrated nature of EU electricity markets, this can add distortions between Member States.
EU-level action is therefore warranted, in order to ensure the minimum degree of harmonisation needed to avoid distortion in investment and generation is achieved. The Third Package already lays down a number of rules relating to these changes (notably Article 14 of the Electricity Regulation), and also requires NRAs to take an active role (under the Electricity Directive). Further provisions relating to transmission tariffs are contained in the inter-transmission system operator completion mechanism (ITC) Regulation, aimed at the issues mentioned above.
Whilst much has been achieved, there is still scope for improvement, particularly given the importance of minimising distortions to the benefit of consumers. EU-action is needed to address this as it needs to be coordinated across the EU." [Emphasis in original]

186. The CIA also gave deliberate and careful consideration to the treatment of ancillary services within tariff harmonisation, including the sections below. This demonstrates that the harmonisation of the treatment of ancillary services as delivered through the ITC Regulation was properly considered, such that changes to the definition of ancillary services in the 2019 Legislation and their interaction with the ITC Regulation were deliberate and were intended. Paragraph 4.3.4. listed a range of options and includes different potential treatments of ancillary services, while paragraph 4.3.5 provided a comparison of these options

"4.3.5. ...

There are two sub-issues that have also been considered as part of this option: that of harmonised charges relating to <u>ancillary services</u> and grid losses; and locational charging.

There is significant diversity in charging methodologies with regards to <u>ancillary services</u>. For instance, in most Member States, all costs for balancing services are recovered via charges on load. Only in a few Member States do generators pay grid charges that comprise a specific contribution for the cost related to balancing services.[114] With regards to grid losses, again most European countries recover them through charges on load, but in a few countries the related cost is partly or fully charged to generators.

If charges for <u>ancillary services</u> were to be harmonised, the impact on short-term and long-term electricity system efficiency would depend on the level of the charges and the charging modalities but may not be substantial. If charges for <u>ancillary services</u> were to be more correctly and transparently allocated to the market parties (generation and load) on basis of needs of the parties, market operators would contribute to minimising the overall need for such services, particularly frequency-related services, with more flexible demand and supply. It could, however, contribute to a higher cost-reflectiveness and fairer cross-border

[114] Footnotes have been omitted for clarity, but footnote 33 referenced the GB System of BSUoS charges and the fact that they were split evenly between Generators and Suppliers.

competition amongst generators as the currently diverging charging practices and cost allocation can lead to competition distortions between power generators active in the same integrated regional market." [Emphasis added]

187. The interaction between the ITC Regulation and the proposed recast EU legislation was accordingly considered expressly by the EU Commission as part of the legislative procedure. The Commission must necessarily either have considered that Congestion Management was never an ancillary service in the first place or, if they considered that a revised treatment of Congestion Management was appropriate, that the changes in the Recast Regulation would necessarily lead to a revised interpretation of the ITC Regulation. There would otherwise have been an amendment to the ITC Regulation to clarify the matter, or some saving for a different definition to be applied to the ITC Regulation separately from that applied more generally under the Recast Electricity Regulation.

188. GEMA has nonetheless adopted a construction of one of the terms of the ITC Regulation which is now at odds with the clear wording of the Recast Electricity Regulation and the Recast Electricity Directive. It has treated those component cost elements of BSUoS Charges relating to Congestion Management as being within the scope of the Ancillary Services Exclusion set out in Part B(2)(2) of the ITC Regulation. Accordingly, GEMA treats the expression "ancillary services" in the ITC Regulation as encompassing Congestion Management services for which BSUoS Charges are raised, even though the Recast Electricity Regulation states that such ancillary services do <u>not</u> include Congestion Management.

189. In paragraph 7 of Legal Annex One, GEMA stated that "little or no weight should be attached to the 2019 Legislation as an aid to interpreting the [ITC] Regulation." That was an incorrect approach in law. EU legislation should be construed in context and, for a given regime, holistically. In Case C-491/01 <u>R v. Secretary of State for Health *ex p* British American Tobacco</u> [2002] ECR I-11453, the CJEU at [203] stated: "in interpreting a provision of Community law, it is necessary to consider not only its wording but also the context in which it occurs and the objects of the rules of which it forms part." In Case C-357/13 <u>Drukarnia Multipress</u> [2015] EU:C:2015:253, CJEU at [20]-[21], the Court confirmed that a recast Directive which substantially repeated the content of its predecessor should be construed in the light of the case law relating to the earlier Directive. It also noted that it was appropriate to consider the Directives alongside one another.

190. The CJEU has occasionally confirmed that later legislation cannot alter the clear, contrary meaning of earlier legislation for an earlier period, but here it is a question of construing two pieces of existing legislation sympathetically with one another and doing so from the coming into legal effect of the Recast Electricity Regulation on 1 January 2020. Otherwise, the meaning adopted by the Commission in delegated legislation would be at odds with the definition given in the parent legislation (as now recast). A contrary definition would now be *ultra vires* the enabling EU legislation. In short, GEMA has adopted a construction of the ITC Regulation which would render it inconsistent with the enabling legislation under which it is to be treated as having been made. To put the point in context, the Commission would not now be able to adopt a Network Code dealing with ancillary services which gave them a definition which was inconsistent with the Recast Electricity Directive, as that would be *ultra vires* Article 59 of the parent Regulation. For the same reason, it is denied that GEMA may lawfully construe the ITC Regulation in a manner that is inconsistent with it.

191. Even if, following the expiry of the Implementation Period on 31 December 2020, a purely EU method of statutory interpretation is inappropriate, the UK legislature has chosen to maintain the ITC Regulation in force with only minor amendments. It has also kept the Recast Electricity Regulation as retained EU legislation. What is significant, in this regard, is that the UK legislature has chosen to retain the ITC Regulation with no separate treatment of the "ancillary services exclusion" and no distinct definition given: see paragraph 94 above. However, the UK legislature has also chosen to retain the Recast Electricity Regulation, together with its definition of "ancillary services". But it has done so while making express amendments to bring the new definition of "ancillary services" into the framework of UK law.

192. In particular, the Amendment Regulations 2020 by Schedule 4 make some modest changes to the terms of the Recast Electricity Regulation which is otherwise treated as retained EU law under section 3 EUWA 2018. This includes certain amendments to the definitions used within the Recast Electricity Regulation. For present purposes, it is noteworthy that the amended UK law definition of 'ancillary service' is given as follows:

> " 'ancillary service' means a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, **but not including congestion management**;" [Emphasis added]

193. The Parliamentary draftsman, recognising that a cross-reference to the 2019 recast Directive would produce an anomaly in circumstances where that Directive is no longer directly binding on the UK, chose instead to replicate the Directive's definition of ancillary service directly into the retained EU Regulation.

194. The UK legislature has not simply chosen to adopt the ITC Regulation without any relevant modification, in circumstances where an amendment would necessarily have been made if the UK intended to depart from the meaning of 'ancillary services' given under EU law as it currently stands. It has gone further and positively endorsed the updated definition provided in the EU framework by the Recast Electricity Regulation. In circumstances where the UK has also committed to maintaining regulatory alignment with the EU in the electricity market, the amended definition sanctioned by the Amendment Regulations 2020 is also the appropriate one to be applied from a policy perspective.

195. GEMA's decision unlawfully fails to give effect to this definition. In doing so, it has given the *retained* ITC Regulation a definition which is *ultra vires* that found in the superior *retained* Recast Electricity Regulation (under which the ITC Regulation is to be treated as having been made). See, by analogy, R v, Secretary of State for Social Security, *ex p* Joint Council for the Welfare of Immigrants [1997] 1 WLR 275, CA per Waite LJ at p. 293.

(b) The treatment of the relevant BSC Charges

196. GEMA also erred in treating the relevant BSC Charges as falling within the scope of the Ancillary Services Exclusion. The relevant BSC Charges are the contributions which Generators make to the Main Funding Share and Supplier Volume Allocation ('SVA') (Production) Funding Share elements of BSC Charges. In substance, these are the costs of funding the entity Elexon, which discharges administrative functions in the operation of the Balancing and Settlement Code ('BSC'). The following explanation is given of Elexon's role in the GEMA Decision in P396, *Revised treatment of BSC Charges for Lead Parties of Interconnector BM units* dated 6 March 2020 ('P396') at p. 2:

"The BM is the principal tool used by National Grid Electricity System Operator (NGESO) to balance the electricity system in real time. Generators and demand with flexibility in their portfolios submit offers (to increase generation or decrease demand) and bids (to decrease generation or increase demand) to NGESO via the BM. The Balancing and Settlement Code (BSC) is a document arising from the operation of standard Licence Condition C3.1 that sets out the governance arrangements for this electricity balancing, and the settlement processes that arise from it.

In accordance with Condition C3.1B of their electricity transmission licence, NGESO established ELEXON to administer the BSC. ELEXON's role is to "*provide and procure facilities, resources and services required for the proper, effective and efficient implementation of the BSC*". ELEXON recovers BSC Costs from parties to the BSC, including Interconnector Users, via a monthly charge known as BSCCo Charges. The methodology for determining how ELEXON recovers its costs via BSC Charges is set out in Section D of the BSC." [Footnotes omitted]

197. GEMA in P396 accepted a modification proposal which had the effect of excluding Interconnector BM Units from paying the Main Funding Share and SVA (Production) Funding Share.[115] A central consideration for GEMA was whether Main Funding Share and SVA (Production) Funding Share BSC Charges were "access charges" for the purposes of the Recast Electricity Regulation. The Recast Electricity Regulation provides that access charges must not be recovered from Interconnector Users. If the relevant BSC Charges were access charges, they would therefore have to be removed: see p. 4 of the P396 Decision.

198. GEMA determined (pp. 4-5) that the relevant BSC Charges were indeed access charges. They were required to be paid to access the GB electricity transmission network. Balancing was an integral part of network management, which a network user could not simply decline to use. The concept of 'charges' in the Recast Electricity Regulation was not confined to the physical cost of providing access to the network. The administration of the balancing system would need to be paid for too. Under Article 18(3) of the Recast Electricity Regulation, only producers and Consumers could pay network access charges.

199. The consequence of this decision is that GEMA has necessarily treated the relevant BSC Charges as network access charges which Generators[116] are required to pay. Moreover, the impact of removing the Interconnector BM Units from the charging scheme

[115] See generally *Tindal 1* at [5.27]-[5.32].
[116] Suppliers also have to make a contribution to paying the Elexon funding costs. However, that is not relevant for this Appeal.

is that Generators must pay more in network access charges than previously was the case. GEMA necessarily accepts, therefore, that these charges are charges for the use of the transmission network. GEMA nonetheless concluded in the contested Decision that the relevant BSC Charges fell within the Ancillary Services Exclusion and thus were not to be included within the annual average transmission charges paid by Generators when calculating compliance with the statutory range.

200. In so doing, GEMA has erred in its construction of the Ancillary Services Exclusion and failed to comply with its statutory objective of regulatory consistency. At p. 12 of the contested Decision, GEMA incorrectly states that the BSC Charges fall within the Ancillary Services Exclusion as a matter of EU law. That is wrong. GEMA has found in the P396 Decision that the relevant BSC Charges were required in order to gain access to the GB network. In other words, the relevant BSC Charges are payable in order to secure the ability to transmit electricity across that network. The service which the payer receives is one of transmission. It is not the receipt of some lesser, ancillary service. If GEMA had taken the view that the relevant BSC Charges were for a service distinct from transmission, necessary nonetheless for the separate operation of the transmission system, it would not have found that they were access charges in the P396 Decision. The contested Decision and the P396 Decision are accordingly inconsistent with one another in respect of the treatment of the relevant BSC Charges.

201. Properly construed, GEMA was right to consider that the relevant BSC Charges are paid in return for access to the transmission network. Generators pay a substantial sum of money to fund the administrative activities of NGESO, for example, and there can be no suggestion but that the charges which are levied for that purpose are transmission charges and do not fall within the Ancillary Services Exclusion. They are part and parcel of the charges payable for use of the transmission network. The payment of relevant BSC Charges to fund the administrative activities of Elexon is no different in principle. Those charges have to be paid if a Generator wants to use the transmission network, since a Generator cannot simply decline to use the service.

202. In Legal Annex One at [10] to [13], GEMA seeks to imply that Elexon's role is limited to the clerical administration of a financial settlement model by which Generators and Suppliers pay or receive sums of money to reflect the underlying physical balancing of the

electrical flows on the transmission system.[117] That is also at odds with the approach adopted in the P396 Decision. In that Decision (p. 40, GEMA expressly stated that "balancing (both energy balancing and system balancing) are integral parts of network management." The main service provided by Elexon is in energy balancing and the administration of transmission flows, which is a primary activity of the operation of the transmission system (not an ancillary one). Charges paid for Elexon to conduct activity which is integral to network management and which is required for access to the network to be given cannot be construed as related to "ancillary" services. GEMA has also at p. 12 of the contested Decision assessed the proposed inclusion of the BSC Charges against the ACOs and found that the Baseline better achieves those objectives. That is, with respect, irrelevant. Since the charges do not fall within the Ancillary Services Exclusion, they have to be taken into account when assessing compliance with the range for annual average transmission charging set by the ITC Regulation.

(4) The Fourth Ground of Appeal: fundamental errors of appraisal

203. In reaching the contested Decision, GEMA took into account what it stated were the conclusions derived from an Impact Assessment conducted as part of the TCR SCR procedure. At p. 27 of the contested Decision, GEMA concludes that there were "significant consumer benefits associated with the changes that will be implemented through CMP317/327." GEMA also concluded that "the distributional impacts on affected generators, who will pay higher charges as a result of this decision, to be acceptable when considered alongside the benefits." In so finding, the contested Decision has significantly overstated the Consumer benefit and understated the Generator detriment, including the detriment to the long-term generation of renewable energy, which would arise from the contested Decision.

204. As set out in Section 6 of *Tindal 1*, GEMA's analysis of the relative impact of the contested Decision on Generators and Consumers suffered from the following flaws:

204.1. The estimated impact on Generators was additional costs in the order of £639 million in charging year 2021/22 alone. This figure would increase to over £1 billion per year by charging year 2025/26.

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[117] See generally *Tindal 1* at [4.2]-[4.9] and [5.21]-[5.26].

204.2. Generators would not be able to recoup all or most of these costs from their customers or, in turn, from Consumers. Generators had planned for prices some years ahead and their behaviour in the Capacity Market and in entering into Contracts for Difference ('CfDs') reflected their understanding of the application of the range on permissible annual average transmission charges to be paid by Generators as set by the ITC Regulation. Generators were locked into this investment planning and could not now change their decisions.

204.3. The regulatory uncertainty arising from GEMA's conduct gave rise to economic and commercial risks which would inevitably reflected in future investment decisions by industry participants and which would have a chilling effect on renewable energy generation and would ultimately translate into higher prices for Consumers.

204.4. GEMA has materially overstated the perceived Consumer benefit, since its reference at p. 1 of the contested Decision of approximately £300 million per year was based on the total suite of measures contemplated under the TCR Decision and not simply the changes effected by CMP317/327. The Net Present Value ('NPV') of the estimated annual, levelized Consumer benefit is around £33 million per annum, but that was reflective of large distributional transfers from Generators to Consumers and also was subject to caveats about the high degree of volatility. A large amount of the perceived Consumer benefit was attributable to GEMA's treatment of embedded benefits.

204.5. Ofgem's own modelling showed that the impact of the contested Decision on total system value overall is either £zero, or detrimental.

204.6. The Impact Assessment failed to take into account the impact of increasing the cost of capital and increasing the risk margins that Generators are likely to face following the contested Decision. The negative impact of this over time would remove the perceived Consumer surplus entirely. Nor did the contested Decision follow the correct principles of cost reflectivity, so no perceived benefit would arise from locational pricing.

204.7. The Impact Assessment also failed to take into account the negative effects arising from the detrimental impact on the competitive position of GB Generators compared with their EU counterparts.

204.8. Taken together, the various factors considered in *Tindal 1* will tend to result in a less economically efficient electricity system and therefore a more expensive system, whose cost will ultimately be borne by customers over the long term. The significant detriment occasioned to Generators would not therefore be subject to any countervailing systemic benefit to Consumers in the long-run.

(5) The Fifth Ground of Appeal: failure to have proper regard or give due weight to the statutory and CUSC objectives when setting a target towards zero charging for Generators

205. SSE contends that the contested Decision fails to have proper regard or give appropriate weight to the desirability of reducing annual average transmission charges paid by Generators in GB to as close to zero as possible. The statutory cap of €2.50/MWh, consistently with GEMA's stated position, given to the CMA [7.14(g)], should not be treated as a target for transmission charging, but should be the maximum within a permitted range. In order to prevent the statutory cap *de facto* becoming the prevailing rate, GEMA should have found that a target should be set for transmission charging to bring the level down over time, with an aim of achieving zero annual average transmission charges paid by generators in GB. This would promote charging transparency, not affect cross-border trade, not undermine the internal market and lead to a better fulfilment of the objectives identified by the EU and the UK legislatures in policy statements.

206. The Terms of Reference for the CUSC Workgroup for CMP317 required at [5(c)] that the Panel consider "the most appropriate target," in the light of statements made by Ofgem during the course of the CMA appeal of CMP261. This was then addressed in section 3 of the FMR for CMP317/327. The FMR at [3.1.4] noted that the CMA had recorded GEMA's stated position on the statutory cap and the desirability of it not becoming the target for transmission charges. The CMA at [7.14(g)] of its Decision noted that:

"€2.5/MWh is a cap, rather than a target. GEMA does not have a policy of imposing the maximum transmission charges possible under the Regulation. GEMA submitted that it had been seeking to prevent a breach of the Cap rather than aim for a charge of €2.5/MWh..." (Footnotes omitted)

207. As noted at paragraph 128 above, the ERGEG Guidelines noted that most Member States set the G charges at or close to zero. GEMA failed to take properly into account the adverse impact on the competitive position of GB Generators and the higher cost to customers which would result from this competitive disadvantage, as well as the fact that not setting a target makes it more difficult and more expensive to build low carbon generation plant within the GB regime and therefore meet the net-zero climate change

targets set by central Government. GEMA also failed to take into account the effect on cross border trade that this change would have in terms of Article 8(7) of Regulation 714/2009 and neither did it consider the effect, in terms of undermining the internal market, set out in Recital (10) of the ITC Regulation.

208. That policy aim was followed by GEMA in the TCR Decision. At p. 8, GEMA noted that it had decided to levy residual charges on final Demand users, which would make residual changes simpler and more transparent. At [3.50] *ff* (p. 49), GEMA sets out its reasons for moving to a fixed residual charge for final Demand Consumers only, with distinct arrangements for unmetered sites. The consequence for TNUoS charging was that the total transmission residual was henceforth to be recovered from Demand customers, as outlined at [3.57] (p. 56 *ff*). That policy has the added advantage of ensuring that the true costs of electricity generation and distribution lie with the final Consumer, rather than face distortions between TOs, Generators and Suppliers at interstitial parts of the supply chain.

209. GEMA in its TCR Decision did not consider that the need to comply with the ITC Regulation presented any obstacle to its decision to set TGR at zero. At [4.77] (p. 123), it anticipated that the CMP317 procedure would evaluate whether there was any need for reconciliation in the light of any breach of the upper or lower limits set by the ITC Regulation; and what the design of such reconciliation process would comprise. It accepted "that a negative adjustment charge may be required in the future to ensure compliance with the [ITC] Regulation."

210. In addition, in the CMP317/327 FMR Panel members identified the following advantages of following a target of €0.00/MWh for transmission charging:

210.1. Workgroup members identified that the effect of setting 'no target' is that in practice a target of €2.50 MWh is set, subject to any adjustment. Without a target figure, the effect would be to maximise annual average Generation transmission charges of €2.50 MWh (except for charging year 2021/22): see [3.1.6] of the CMP317/327 FMR;

210.2. Fixing a target would improve regulatory certainty and enable Generators to bid for CfDs or bid in to the Capacity Market at more economical rates, since the pricing for risk could be reduced, as a result of forecasting benefits for stakeholders: [3.1.8].

It would also facilitate the building of flexible dispatchable generation in GB to deliver security of supply (a factor of perhaps greater weight now the UK is no longer a Member State of the EU).

210.3. Targeting €0.00/MWh would achieve comparability with other transmission markets across the EU.[118] It would also achieve more consistent treatment with Embedded Generators, who as a result of the CMP264/265 Decision paid average Locational Charges of €0.00/MWh: [3.1.9]. No transmission charges were paid by Generators in 17 of the 27 then other Member States, so targeting €0.00/MWh would level the playing field in terms of comparability with other EU based Generators: [3.1.15];

210.4. It would also reduce the risk of a breach of the €2.50/MWh upper limit set by the ITC Regulation, but also with a lower risk of charges falling beneath the €0.00/MWh floor set by the ITC Regulation at the same time: [3.1.10]. It would also give leeway given the ambiguity over the nature and extent of the Connection Exclusion and the Ancillary Services Exclusion: [3.1.11];

210.5. Targeting €0.00/MWh therefore commanded the support of most Workgroup members on the basis of the principle to be achieved and the wider benefits it would bring: [3.1.14]. The contested Decision at p. 17 fails to reflect this outcome, portraying the views of the members as "mixed" (p. 17).

211. The contested Decision failed to set a target and was flawed by reference to the achievement of the CUSC objectives by which it was to be assessed. In terms of ACO (a), <u>facilitating competition</u>, by failing to set a target at or approaching €0.00/MWh the contested Decision will tend to make it relatively cheaper for developers to build all types of generation in interconnected countries and import power into GB over interconnectors. This results in a distortion to competition and has a detrimental impact on cross-border trade. As set out by the Workgroup, in the absence of a target at or tending to €0.00/MWh, the ceiling of €2.50/MWh tends to act as a marker for the price to be set and *de facto* becomes the charge actually levied. That is demonstrated by an analysis of the historical and forecast figures: see *Tindal 1* at [7.24]. The ceiling set for GB Generators at €2.50/MWh is higher by a significant margin than the ceiling set by the ITC Regulation for most continental competitors (excluding only Denmark, Sweden, Finland and Romania as

[118] See also p. 4 of the Powerpoint presentation produced by Waters Wye Associates, Annex 6 to the FMR.

well as Ireland, Northern Ireland and GB[119]) at €0.50/MWh. If the ceiling tends to set the prevailing charge over time, then a systemic level of charging price discrimination develops between GB Generators and Generators based in most other EU Member States.

212. The contested Decision fails to take this factor into account, adequately or at all. Instead, it focuses (at p. 17) exclusively on competition between: (i) Transmission Connected Generation ('TG') and Larger Distributed Generation ('Large DG'), on the one hand; and (ii) Smaller Distributed Generation ('Small DG') on the other. In adopting that focus, GEMA has extended the disparity of treatment between GB Generators and their EU counterparts more widely to Small DG as well.

213. Moreover, if GEMA has concluded (as p. 25 of the contested Decision suggests it has) that Large DG should not fall within the scope of the ITC Regulation, then a policy objective of achieving parity of treatment between Large DG and Small DG is a legally irrelevant factor for GEMA to have taken into account. For the avoidance of doubt, SSE does not accept that GEMA's purported distinction between TG and Large DG, but that does not excuse the internal inconsistency in GEMA's rationale.[120]

214. To the extent that GEMA's decision wished to avoid any disadvantage to Generators located behind customer meters ('BTMG'),[121] this would fail to take into account that BTMG already benefits from an existing, far greater distortionary competitive advantage (such as a BSUoS double benefit and the avoidance of the final consumption levy). So even if generator TNUoS targeted a lower value in the statutory range, then BTMG would still retain a net competitive advantage compared with TG, Large DG and Small DG. GEMA's approach is also inconsistent with its response to the BSUoS Second Task Force. Here Ofgem accepted the BSUoS Task Force majority recommendation that BSUoS should remain charged on a £/MWh volume basis, despite the Task Force and Ofgem explicitly acknowledging that this would unfairly advantage BTMG which could earn a BSUoS embedded benefit which TG, Large DG and Small DG could not. Ofgem's view was that

[119] Set out in Part B(3) of the Annex to the ITC Regulation.
[120] In particular, GEMA had the opportunity to approve a CMP264/265 WACM which would have levelled the GB playing field by providing Smaller Distributed Generation with exactly the same TGR credit benefit as Transmission Connected Generation, but GEMA chose not to approve a relevant WACMs. The charging discrepancy only exists because GEMA permitted it to exist. The rejected WACM would have levelled the playing field of between GB and EU Generation in a fairer way for <u>all</u> GB Generators at all voltage levels of connection.
[121] See page 6 of the contested Decision and its reference to removing the disbenefit for Small DG, which includes "behind then meter" generators; and the analysis at p. 17 based on that same disbenefit for Small DG.

this remaining BSUoS distortion in favour of BTMG was not a significant issue and should not override the larger benefit of delivering a more level playing field between GB Generation and EU Generators. Such a rationale is one that should have been brought to bear in its decision on CMP317/327, but was not.

215. If GEMA did not wish to disadvantage BTMG, it could have afforded it the same treatment as is being proposed for Small DG in a separate charging review procedure. GEMA has indicated it intends for Small DG to begin to pay Generator TNUoS charges in an equivalent way to TG as part of the Access and Forward Looking Charging ('AFLC') SCR. GEMA could have levelled the GB playing field in this way and implemented this AFLC change already, or at least at the same time as the CMP317/327 implementation. However, this AFLC proposal is being delayed by being encompassed within larger changes to DUoS locational charging, as well as Demand charges for TNUoS and DUoS.

216. As for ACO (b), cost reflectivity, nor does the approach advocated by SSE here lead to the loss of locational charging. It is still entirely possible to set relative locational charging for Generators within a regime where total, average charges to Generators as a class tend to €0.00/MWh. In a similar vein, GEMA's assessment of the extent to which the Original Proposal and the WACMs respect the principle of cost reflectivity is flawed. It fails to recognise that the purpose of cost reflective price signals is to provide relative price signals and that the relative price signal to Generators remains the same irrespective of where in the range the target is set for the annual average transmission charges. In contrast, GEMA appears to claim that TNUoS locational tariffs are cost reflective in absolute terms. This goes against GEMA's position on other measures, including the AFLC SCR, where Ofgem has repeatedly described the purpose of locational charging as being to provide relative locational signals. That was also acknowledged by their consideration of changing the Reference Node.

217. As for ACO (d) and specifically compliance with the ITC Regulation, SSE considers that the targeting approach minimises the risk of non-compliance in a more effective way than the adopted error margin. The history set out in section C above is characterised by attempts by GEMA and NGESO to deal with an impending breach of the statutory range shortly before it arises through a series of *ad hoc* adjustments to their definitions of the Connection Exclusion and now the Ancillary Services Exclusion. The regulatory

uncertainty this engenders could be avoided entirely if GEMA instead adopted a policy of targeting an annual average Generators' charge for transmission of €0.00/MWh.

218. As for ACO (c) and (e), for the reasons set out in Ground 4 above, GEMA overstated Consumer savings and understated Generator detriment. Setting a target would have remedied those failings.

(6) The Sixth Ground of Appeal: failure to provide for the phased introduction of the new provisions

219. The contested Decision also fails to have proper regard or give appropriate weight to the desirability of staggering the introduction of the new measures through 'phasing'. SSE contends that the more disruptive impact of the significant change to the charging structure would have been less detrimental to Generators if introduced over the course of two years. In that way, Generators could have adjusted their conduct in the Capacity Market and in their bids for CfDs. This would also have been consistent with the approach adopted by GEMA in the TCR Decision, to which the contested Decision is closely related (as, for example, is witnessed by GEMA's decision to agree to the amalgamation of CMP327 with CMP317). SSE also notes that the Original Proposal from NGESO itself in section 8 recognised that phasing might well be needed. It stated:

"As with CMPs 264&265, which materially affected credits for embedded generators, a phased implementation approach for the solution of this CMP may be preferable, in order to provide Generator Users sufficient time for business readiness."

220. The Terms of Reference for the CUSC Workgroup for CMP317 required it at [4] to consider the issues raised by the Original Proposal and at [5(e)] to consider "other ways of … tackling the defect." It was also empowered to consider any WACMs raised and whether they better facilitated the achievement of the ACOs. The Workgroup decided that they therefore also had to consider implementation issues, including whether or not the proposed changes should be subject to a phased implementation period. This was then addressed in section 9.2 of the FMR for CMP317/327. While there was no consensus as to whether the phased period should be two years or three, the FMR at [9.2.2.] confirmed that:

"The majority of the Workgroup believed that a phasing approach was preferable as it would better allow generator participants in the market to adapt their business models to the changes in the cost base that would occur as a result of the Original Proposal. Other

Workgroup members considered that the intended changes had been well signalled by Ofgem since the beginning of the TCR SCR deliberations and therefore phasing was not necessary."

221. The solution advanced by the Workgroup for phased implementation over a period of two years was set out at [9.2.4] of the FMR. It proposed a Transition Tariff for two years set at one half of the prior expected residual tariff in the Charging Year 2021/22, with no adjustment then made from charging year 2022/23 onwards. Implementation over a three-year period was also considered in the alternative at [9.2.5].

222. GEMA decided not to implement the changes to transmission charges in a phased way, but to introduce the relevant changes with effect from 1 April 2021. It recognised (at p. 14 of the contested Decision) that the majority of Workgroup members thought a phased implementation was preferable, but considered that there had been sufficient time for investors and market participants to anticipate these potential changes. In doing so, it relied solely on a conclusion to that effect for the purposes of the TCR Decision (in which the TGR was set to zero, but no specific ruling on the necessary adjustments to the CUSC was made). GEMA failed to give any consideration to the lack of foreseeability of the nature and extent of the changes made in the Original Proposal beyond those which reflected the Direction to set the TGR to zero. The TCR Decision had made clear that setting the TGR to zero would still require the statutory limits set by the ITC Regulation to be met. But the means by which TGR was to be set to zero <u>and</u> the statutory limits in the ITC Regulation respected was wholly unexplained in the TCR Decision itself. Indeed, it is precisely for that reason that NGESO raised the Original Proposal and commenced the Workgroup procedure for CMP327 and requested that it be amalgamated with CMP317.

223. GEMA's decision was in fact inconsistent with the approach adopted in the TCR Decision. At p. 8 of the TCR Decision, GEMA decided that the implementation of its proposed changes to residual charging should take place in stages. It recognised this would help mitigate any distributional impacts. At [5.58], the TCR Decision noted that:

"5.58. We agree that regulation (to the extent practicable) should be predictable in order to provide a stable regulatory framework for the energy sector, helping to keep costs low for consumers. In this regard, we have been clear that our network charging framework should evolve over time as the system changes. Reforms can be initiated both through Ofgem reviews and industry open governance. Delivering good long-term outcomes for consumers is best achieved by allowing efficient price signals to drive behavioural response so that the system works well, and ensuring residual charges do not create harmful distortions to these signals and are fair.

224. Having applied those principles to the question of implementation in Chapter 6 of the TCR Decision, GEMA then phased the implementation of its changes so that changes to transmission residual charges would take place in 2021 and those to distribution residual charges would take place in 2022. See [6.18] to [6.21] of the TCR Decision (p. 157).

225. GEMA's decision nonetheless failed to apply a consistent approach to the treatment of the additional aspects of the contested Decision which go beyond setting the TGR to zero. The TCR Decision itself envisaged that an adjustment for compliance with the ITC Regulation might be needed. The question, therefore, was whether the necessary adjustment to the level of annual average transmission charging, having otherwise set TGR at zero, should be implemented immediately, or over a two-year period to give Generators a reasonable opportunity to adjust their behaviour and investment strategies.

226. Generators could not have reasonably predicted, prior to the contested Decision, GEMA's change to the construction of the Connection Exclusion and its approach to the Ancillary Services Exclusion. As to the Connection Exclusion, GEMA's approach in approving the Original Proposal is inconsistent with the proper construction of the ITC Regulation in the light of the CMA Decision, properly construed, as GEMA itself recognises (see Ground 2 above). If, contrary to Ground 2 above, GEMA was entitled to adopt a legally incorrect approach as a 'stop gap' measure, it should have mitigated the detrimental impact on Generators from doing so by phasing the implementation over a two-year period, thus reducing the pressure on NGESO to rush through yet another imperfect solution. As to the Ancillary Services Exclusion, this is a wholly new point, arising as a result of changes at EU level to the applicable legislation.

227. Generators had a reasonable expectation that GEMA would take steps to avoid harmful and unnecessary TNUoS tariff volatility. Ofgem has indicated that it is considering changes to the Reference Node as part of its AFLC SCR, which could reduce the value of locational tariffs and therefore obviate the need to use a £ negative adjustment factor to ensure compliance with the ITC Regulation in the long-term. Therefore, GEMA's decision to implement the CMP317/327 Original Proposal from April 2021 will result in a large and short-term step-change increase in Generator TNUoS tariffs for two years (2021/22 and

22/23), before falling back down again once the proposed changes in the treatment of the Reference Node take effect from April 2023 onwards. The CMP317/327 Workgroup wanted to include changes to the Reference Node as a WACM solution in CMP317/327, but it was informed by Ofgem [6.1.1. in the CMP317/327 FMR] that any changes to the Reference Node were within the scope of GEMA's AFLC SCR. Ofgem declined a request from the Chair of the CMP317/327 Workgroup to allow the Reference Node to be considered [6.1.2. in the CMP317/327 FMR] and it could not therefore be considered in CMP317/327. It is contrary to good regulatory practice for GEMA to approve the Original Proposal which introduces such significant tariff volatility. It fails to provide any useful price signal, because Generators cannot (and will not) make investment decisions in response to such volatile, short-term changes of tariffs.

228. Contrary to the contested Decision's conclusions at p. 15, GEMA is incorrect to find that immediate implementation of the Original Proposal better meets ACOs (a) to (e). As to ACO (a), <u>facilitating competition</u>, while setting the TGR to zero in a shorter time-frame will remove the disparities between Large DG and Small DG more quickly, it does so only at the significant cost of imposing a far higher short term burden on transmission connected Generators. The contested Decision gives no indication that GEMA took into account the need to balance the removal of a disbenefit from Small DG against the imposition of a significant change in the level of transmission charges on transmission connected Generators with no sufficient warning. Out of the wide range of WACMs proposed, GEMA chose the option which resulted in the most expensive possible TNUoS charges for transmission connected Generators and maximised the total revenue collected from those Generators.

229. As to ACO (b), <u>cost-reflectivity</u>, the detrimental impact on Generators accordingly has no redeeming benefit of changing behaviour, contrary to GEMA's conclusion on ACO (b). That is because Ofgem's proposals on Reference Nodes (see paragraph 227 above) will not change locational behaviour in the short-term, so only serve to impose significant costs on Generators for no achievable policy benefit. That should have been alleviated, at least in part, through a phased implementation of the changes. Generators also had a reasonable expectation that Ofgem would be concerned with preserving <u>relative</u> price signals, so would not be motivated to maximise the total annual average transmission charges collected from generation, which is what the contested Decision has in fact achieved.

230. In relation to ACO (c), GEMA's reasoning relies upon the need for NGESO to comply with the Direction it issued for TGR to be set at zero from April 2021. SSE takes no issue with that Direction. The question is about how responsive adjustments to the CUSC to give effect to that Direction are best achieved. Setting TGR at zero can be achieved from April 2021, but it does not mean that the necessary adjustments to the CUSC have to impose unforeseen and significant costs' burdens on Generators with immediate effect. The new changes to the CUSC include the adoption of a new adjustment mechanism under Condition 14.14.5, which could have been used to avoid a breach of the upper or lower ranges of the ITC Regulation in the meantime. Alternatively, if GEMA wished to avoid any adjustment mechanism which result in a credit being given to any Generator, then there would need to be a reduction in the value of the Wider Locational Charges themselves. This could be achieved by changing the Reference Node through the AFLC SCR process.

231. As for ACO (d), compliance with the ITC Regulation and EU legislation more generally compliance with the ITC Regulation could have been secured using the new adjustment mechanism, without triggering the excessive detriment to Generators over the next two-year period. Since GEMA recognises in the contested Decision that some element of "truing up" the compliance position is likely to be necessary historically, any adjustment could also have factored in this reconciliation process.

232. Finally, on ACO (e), allowing an appropriate implementation period would ameliorate a large share of the 'generator shock' experienced in the two-year period running from 1 April 2021. For the reasons set out in *Tindal 1* at [7.54] to [7.55], reducing that detrimental impact of the implementation of the changes would promote overall economic efficiency in the implementation and administration of the TNUoS charging regime.

G. RELIEF

233. Pursuant to section 175(6) of the EA 2004, SSE respectfully suggests that the contested Decision be quashed. This would have the effect of returning matters to the *status quo ante* until such time as a further and better Proposal is tabled and approved.

234. Alternatively, SSE seeks an Order that the contested Decision is quashed in so far as it approves all or any of the following elements of the Original Proposal, namely:

234.1. A definition of the Connected Exclusion which treats any Local Assets other than GOS as connection assets, alternatively which treats any Local Assets as falling within the scope of the Connection Exclusion if they are shared, alternatively were shared at the time of the connection of the Generator in question;

234.2. A definition of the Ancillary Services Exclusion which includes the Congestion Management element of BSUoS Charges;

234.3. A definition of the Ancillary Services Exclusion which includes the Relevant BSC Charges;

234.4. A decision not to set any target for average annual transmission charging at £zero or below the upper limit of the statutory range of £2.50 MWh;

234.5. A decision to approve the implementation of the Original Proposal with effect from 1 April 2021, without putting in place any phasing of that implementation over a two year period to 1 April 2023.

235. Yet further or alternatively, SSE seeks a direction from the CMA that the matter be remitted to GEMA for further reconsideration, with GEMA being directed to take into account the factors identified in paragraph 234 above, so that the remitted decision will properly give effect to the CMA's findings in relation to:

235.1. The correct definition of the Connection Exclusion such that those charges along with the charges paid in respect of Congestion Management and Relevant BSC Charges are treated as part of the annual average transmission charges paid by producers;

235.2. The correct definition of the Ancillary Services Exclusion, including the related issue of the correct definition of the Relevant BSUoS Charges and the Relevant BSC Charges such that both those charges are treated as part of the annual average transmission charges paid by Generators;

235.3. The need for a target of €0.00 or less than €2.50 MWh to be set for annual average transmission charges paid by Generators;

235.4. The need for transitional provisions to be made to give effect to a phased implementation of the modifications over a two-year period.

236. SSE nonetheless contends that a more useful form of relief would be for the CMA to confirm that one of the proposed WACMs represents a better regulatory solution to the

various issues raised above than the Original Proposal. To that end, SSE would respectfully suggest that elements of WACM14, WACM72 and WACM79 could be combined to give effect to the CMA's conclusions in this appeal and could be implemented, if appropriate, through the introduction of a mid-year charging review procedure as soon as possible.

237. Nonetheless in order to be able to make meaningful suggestions in this regard, SSE would need more data than is currently available to it. SSE understands from a meeting of the Transmission Charging Methodologies Forum ('TCMF') on 7 January 2021 that NGESO has performed an analysis of electricity outturn figures for each year going back to 2016/17 in order to be able to assess the compliance of the transmission charges actually levied with GEMA's modified interpretation (in the contested Decision) of the ITC Regulation. SSE notes that the availability of such data, to be considered by reference to competing constructions of the Connection Exclusion, Ancillary Services Exclusion and the Relevant BSC Charges, would significantly help in determining any particular remedy proposed. SSE accordingly reserves the right to make further submissions on relief in the light of GEMA's response to the appeal and any further information provided by NGESO.

238. In the event that SSE is successful in its appeal, it will seek an appropriate order for its costs of and occasioned by it.

KIERON BEAL QC

ADDLESHAW GODDARD

12 January 2021

SCHEDULE 1: ADDITIONAL APPELLANTS

1. SSE Generation Limited, of No 1 Forbury Place, 43 Forbury Road, Reading RG1 3JH

2. Keadby Generation Limited, Keadby Power Station Trentside, Keadby, Scunthorpe, United Kingdom, DN17 3EF

3. Medway Power Limited, No 1 Forbury Place, 43 Forbury Road, Reading RG1 3JH

4. Griffin Windfarm Limited, Inveralmond House, 200 Dunkeld Road, Perth, PH1 3AQ

5. SSE Renewables (UK) Limited, Millennium House, 25 Great Victoria Street, Belfast, Northern Ireland, BT2 7AQ

6. Keadby Windfarm Limited, No 1 Forbury Place, 43 Forbury Road, Reading RG1 3JH

SCHEDULE 2: INTERESTED PARTIES

1. National Grid Electricity System Operator Limited
2. Banks Renewables Limited / Banks Renewables (Kype Muir wind farm) Limited / Banks Renewables (Middle Muir wind farm) Limited
3. Centrica
4. Citizens Advice
5. Drax Group Plc
6. E.ON UK
7. EDF Energy Customers Limited
8. Enenco
9. ENGIE
10. ESB GT
11. Fred Olsen Renewables
12. Highlands and Islands Enterprise
13. Innogy
14. Northwind Associates
15. Neven Point Wind Limited
16. npower
17. Orkney Islands Council
18. Ørsted
19. RES UK & Ireland Limited
20. RWE Supply & Trading GmbH
21. Scottish Power Renewables
22. Sembcorp Energy UK
23. Statkraft UK Limited
24. Uniper UK
25. Ventient Energy
26. Waters Wye Associates
27. Zenobe Energy Limited