

Centrica plc

Millstream  
Maidenhead Road  
Windsor

SL4 5GD  
[www.centrica.com](http://www.centrica.com)

Response submitted to: RII03@ofgem.gov.uk

26 August 2025

### **Draft Determinations Consultation**

Centrica welcomes the opportunity to respond to the consultation on the Draft Determinations (DD) for electricity transmission, and the gas transmission and distribution networks. Our company is active across the energy value chain under a wide range of regulatory frameworks. Many of the elements of the DD approaches read across into investments such as Sizewell C where we are participating, and where the RAB based framework is overseen by Ofgem. Our retail business is also partially subject to a price cap with many similar elements.

We recently responded to the DESNZ Review of Ofgem noting the ever-widening range of investment being underpinned by Ofgem determinations on allowed revenues. As a general point, we consider that such decisions need to have greater focus on attracting investment. This applies not only to production and networks, but also to the retail sector where cost recovery remains essential to underpin a stable retail sector and investment in new technologies and innovative products.

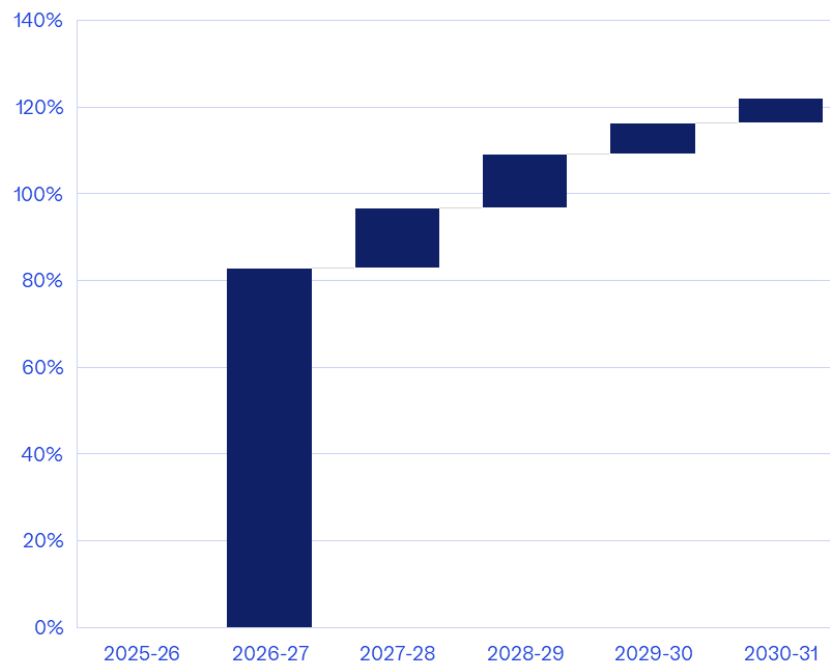
### **Impacts on the retail sector**

The DD proposals will increase domestic consumers' bills sharply, especially alongside other measures such as the delayed recovery of the Warm Home Discount (WHD). We estimate that electricity Transmission Use of System (TNUoS) charges will increase by ~87% in 2026-27 from current levels today.<sup>1</sup> Such an increase creates a risk to suppliers and may negatively affect the stability of the retail market due, in part, to the unexpected and negative impact on fixed-term energy supply contracts. We note that some suppliers are currently not meeting the Minimum Capital Requirements.

---

<sup>1</sup> Based on the domestic bill impact analysis in the Impact Assessment.

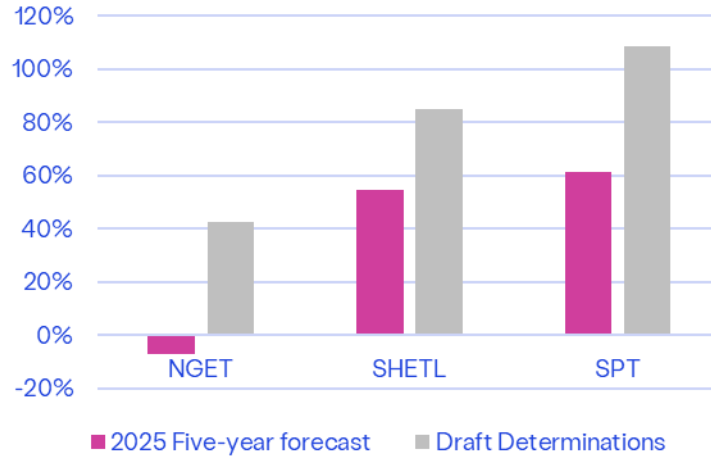
### Year-on-year revenue increases to 2030-31



This is also a significant concern for the non-domestic retail market because fixed-term contracts and cost certainty are the preference of a large proportion of non-domestic energy users – with consequential impacts for end consumers. The revenues proposed in the DDs are significantly higher than those published by NESO. Suppliers operating in the non-domestic sector rely on these cost indicators to help set long-term fixed-rate contracts for customers. Fixed contracts are often signed for up to five years. Any changes to forecasted costs therefore have a material impact on supplier margins for contracts that have already been agreed. Concerns about fixed contracts also apply to the domestic sector – about a quarter of customer contracts in the domestic market are fixed rate, although with contracts of typically 12 months, the overall financial impact is lower but still significant for 2026/27.

We have observed that forecasts for individual TO revenues have increased by as much as 104% since NESO published its 2024 Five Year Forecast, which was published only about 18 months ago.

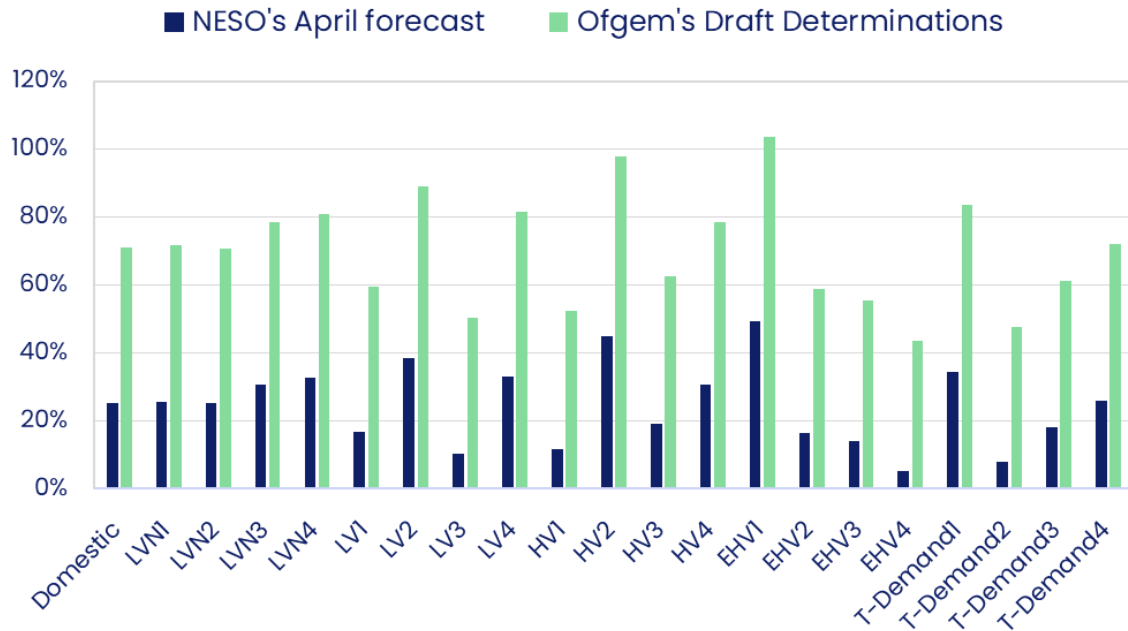
**Variances vs NESO's 2024 Five-year forecast**



We estimate that across the B2B market, suppliers will face c.£500+ million in additional costs in existing fixed contracts due to the DDs. Suppliers will have to seek ways to recover these costs from existing or future contracts - undermining the certainty that fixed contracts are designed to provide. This outcome is directly in contrast to Ofgem's stated objective of "*shaping a retail market that works for consumers*".

We also highlight the negative impact of the steep increases on non-domestic consumers. Fixed contracts are in high demand: according to Ofgem's research, 68% of businesses were on a fixed-rate electricity contract (Businesses' Experiences of the Energy Market 2023 - Main Research Report). Businesses particularly value the certainty, as it allows them to budget more accurately. All other things being equal, TNUoS charges for non-domestic consumers in 2026-27 will be about 70% higher compared to current charges today.

**Variance between current non-domestic TNUoS charges (NESO's April forecast) and TNUoS charges resulting from Ofgem's Draft Determinations**



The DD proposals as published, in combination with misleading signals on future network charges and the absence of inclusion of the business segment in Ofgem's impact assessment, will lead to widespread disruption in the non-domestic supply market. This could threaten the solvency of some providers, alongside the requirements to recover other additional costs such as the Energy Intensive Industries (EII) Network Charge Compensation Scheme extension to 90% relief and the Nuclear RAB levy, both of which still carry uncertainty on cost levels and timing despite being at implementation stage. This is in addition to even greater uncertainty on other liabilities and mechanisms that will fall on suppliers in the coming months, such as the levy exemptions for 7,000 businesses as announced in the Industrial Strategy, end-user bill discounts for Transmission Network Infrastructure, and the Debt Relief Scheme.

Ofgem's impact assessment is incomplete and therefore intrinsically flawed. Despite stating in the introduction that Ofgem would “quantify bill impacts on energy consumers, including non-domestic consumers comparing bill impacts to current levels”,<sup>2</sup> Ofgem has neglected to include any meaningful analysis or results for the non-domestic segment. This appears to be on the basis that there is “no simple calculation”<sup>3</sup> to be made of the effect on a non-domestic consumer. Ofgem states initially that “the effect of RIIO-3 varies significantly between non-domestic consumer types”, but then surprisingly, without evidence of analysis, Ofgem reaches the conclusion that the net bill impact of RIIO-3 “should be relatively small for the majority of non-domestic consumers”. These statements are clearly inconsistent. Ofgem's lack of consideration of consumers outside the price cap and EII segments leaves a very large gap in the assessment of impacts on consumers, markets and, by extension, economic growth.

<sup>2</sup> RIIO-3 Draft Determinations – Impact Assessment, p. 8.

<sup>3</sup> Ibid, p. 42.

### **Scale of Investment Programme**

The DDs must place strong incentives on electricity licensees to deliver the step change in network investment that is widely recognised as needed. The success of Connections Reform and delivery of the Clean Power 2030 objectives is dependent on timely delivery of increased transmission capacity.

Meanwhile for the gas sector, there are important decisions to be taken on repurposing and the potential decommissioning of parts of the network. This, in turn, raises questions about the profile for depreciation. Our view is that there remains too much uncertainty around the timetable for decommissioning of the gas system in the longer term to do more in this area.

### **Incentive Structure and Cost of Equity**

The key underlying decisions here are around the risk-return trade-offs and the concept of a “fair bet” that Ofgem has used to tailor the incentive structure, and estimate an appropriate cost of capital. We do not comment in general on the approach taken in the DDs to estimating cost of equity and expect Ofgem to continue to use its judgement in this area. However, we would suggest a strengthening of the incentive structure around project delivery and believe this could be accommodated within the proposed risk-return envelope without any adjustment to the cost of equity.

We have expanded on some of these points in the attached Annex in responding to a selection of the questions in the consultation document. We have also prepared some separate material for submission in a confidential paper shortly.

## **ANNEX: RESPONSES TO SELECTED QUESTIONS**

### **ELECTRICITY TRANSMISSION**

#### **ETQ4-7          Connection Incentives**

The ODI-F incentive proposed by Ofgem relating to CSNP outputs (CSNP-F) is asymmetric in favour of transmission companies in that there is both a deadband 12-month period and the ceiling position incentive is 10% compared to the downside of 5%. Given the importance of prompt delivery of new transmission capacity, Ofgem should consider shortening or removing the deadband period.

With respect to the Connections Capacity ODI developed as a result of the end-to-end review, in theory Option 1 could have benefits by focussing the TOs on a potentially clearly definable deliverable, i.e. of the timely connection of projects in the reformed connections queue. If Ofgem pursues this route, it must ensure that no projects in the queue are excluded from the incentive. This means that, as well as demand connections, it must include all generation connecting via the distribution network that is subject to the TMO4+ process – irrespective of whether the generator is contracting directly with NESO (e.g. via a BEGA) or via the DNO. For clarity, Option 1 should also not be only limited to projects that are in the existing queue and that submitted evidence by August 2025. Option 2, as an aggregated approach, implies a calculation which would be more theoretical.

Finally, we agree with the removal of the incentive linked to the Quality of Connections Survey (QoCS) for the reasons Ofgem notes in the consultation document.

#### **ETQ16-20      SO:TO Interface**

We would support a limited ODI-F, but only for the application of genuinely new techniques, and the structure needs reviewing to ensure that TOs are not over-rewarded. The fundamental issue here is how to define ‘new’.

We would prefer use of a margin on the TOs’ cost to develop and implement new solutions, instead of a linkage to constraint costs savings because the rewards are massively disproportionate.

#### **ETQ32-36      Generation and Demand Connections Volume Driver**

In general, we agree with the approach Ofgem sets out in terms of using simple single rate volume drivers, the exclusion of extreme values and the separate treatment of atypical projects. Regarding the profiling of expenditure, Ofgem should examine whether a phased approach is more reflective of actual programme management and better reflects the interests of consumers, as well as potentially improving indicators on debt financeability.

### **GAS TRANSMISSION**

#### **GTQ1          Obligation to Cooperate with NESO**

We agree with the proposed licence condition.

**GTQ15            UIOLI Biomethane Connections**

We agree with the proposed mechanism.

**GTQ56            TIM Percentages**

We support maintaining the sharing percentage at 39% as in RII02.

**GAS DISTRIBUTION****GDQ20            Biomethane Connections**

We agree with the proposed mechanism.

**GTQ46            TIM Percentages**

We support maintaining the sharing percentage at 50%, similar to the levels in RII02.

**FINANCIAL ANNEX****FQ1-FQ6            Cost of Debt**

We disagree with Ofgem's intention not to have a transition mechanism in the implementation of the nominal allowance for fixed rate debt. Ofgem's justification (paragraph 2.41) is unconvincing, given that consumers will face higher upfront costs from April 2026 under the new arrangements if they are implemented straight away. Phasing in over e.g. a 3-year period would be appropriate. This would help mitigate the overall immediate impact on bills and avoid the likely disruption to elements of the retail market from the resultant abrupt increases in network charges.

**FQ18-21            Debt Financeability and Resilience**

Ofgem's proposal to reduce the capitalisation rate for bucket two totex spend from a natural average rate of 100% to 85% for all licensees should be reconsidered and a transition period applied.

Ofgem's approach creates the risk of financeability problems transferring down the value chain, especially to the extent that charges increase immediately in April 2026.

**FQ24-26            Regulatory Depreciation**

There is too much uncertainty around the pathway of heat decarbonisation and we do not believe that the immediate bill impact is fully justified. We also have the view that some means outside customer bills will be needed to fund a residual element of depreciation of gas networks and the decommissioning requirements.