Reformed National Pricing delivery plan

Citizens Advice response

July 2026

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Citizens Advice is responding to DESNZ's recent consultation on Reformed National Pricing. We recognise that this response is submitted after the deadline for the consultation. The reforms under consideration by DESNZ are important and we want to ensure that the consumer view is heard.

The case for change set out below is consumer-led. Balancing costs reached £2.7 billion in 2024/25, of which £1.9 billion was constraint costs. Without reform, they are projected to reach £4–8 billion per year by 2030. This scenario would add £60–140 per household per year to bills at peak, falling disproportionately on lower-income households as a share of disposable income.

Greater strategic planning through the Strategic Spatial Energy Plan (SSEP) is necessary. DESNZ's own indicative analysis suggests RNP investment-side reforms — ensuring investment happens in the right locations and at the right times — could yield £10–20 billion (present value) in benefits over 2030–2050. This is equivalent to up to £20–40 per typical dual-fuel household per year by 2040 (RNP Delivery Plan, Chapter 1). Additional near-term measures targeted at constraint costs are estimated by DESNZ at up to £1 billion of savings in 2030. Accelerating three key transmission projects could add another £4 billion. This shows the importance of progressing this work at pace and with ambition.

Constraint costs are expected to rise because of a market design that systematically socialises risk onto consumers. For instance:

- seabed leasing in England and Wales has lagged Scotland, producing a geographic imbalance that drives constrained-zone clustering in AR auctions.
- CfD allocation rounds have proceeded with firm access and without network-readiness screening, with AR7 awarding 6.5 GW of offshore wind behind constrained boundaries commissioning in 2030–2032, well before EGL3 and EGL4 reinforce B6 in 2033.
- Retained EU Regulation 838/2010 (the Limiting Regulation) caps generator TNUoS at €2.50/MWh, weakening locational price signals for generators and shifting 84% of network cost recovery onto demand.

In our view, DESNZ's framing of the policy task — to "deliver the SSEP at maximum confidence and lowest cost" — needs reconsideration. From the consumer perspective, the task is to ensure that the SSEP, combined with market design, policy and regulation, delivers the lowest cost secure and reliable decarbonised power system. The primary user of SSEP should be the Centralised Strategic Network Plan (CSNP) so that the electricity network can be efficiently built ahead of need. Other users (CfD design, locational charging, support-scheme reform) should use SSEP to inform calibration of market-based instruments. The SSEP should be a planning input that complements efficient market design. In our view, it is unlikely that any national pricing system will deliver efficient market design in the medium term.

We recommend that DESNZ takes three steps as a single coherent package:

Immediate near-term priorities (2026–2029). Expedite the measures that reduce consumer costs now. The most consequential single step is CfD eligibility screening calibrated to optimal economic curtailment, ideally applied from AR8 in 2026. Some over-offer of connection capacity above the CSNP planning line is essential — to drive competition in CfD auctions and absorb project attrition — but it must be bounded by economic optimisation. Ofgem's February 2026 letter on TMO4+ Protected Projects shows the current system fails this test. 210 of 340 projects whose dates were supposed to be ring-fenced are facing changes, around 135 (40%) for network-driven reasons.

Aligned operational measures led by NESO can save £1.5–2.5 billion per year once running. But only if they can proceed without waiting for the slower, more contested elements of the RNP package. We want to avoid a position where disagreements over, for example, code modifications delay significant efficiency savings for consumers.

Make the strategic choice on the enduring market design now. The RNP delivery plan requires a commitment to a long-term target market model. Consumers and investors would benefit from clarity that the system is moving toward more efficient market design.

Coherent medium-term bridge (2029–2035). Of the options taken forward, Option 3 (directive connections combined with stronger locational charges) delivers medium-term consumer outcome. Option 2b is acceptable only with a substantial package of additional safeguards. Option 2a places excessive weight on SSEP modelling accuracy. Whichever option is chosen, all medium-term measures must be designed for compatibility with the eventual target model so that path dependency is avoided.

Q 1a) Do you agree with the key levers that we have identified for supporting the delivery of the SSEP? Please provide rationale and evidence for your answers.

We broadly agree that the six levers identified — network build, seabed leasing, planning reform, the connections regime, locational charging, and generation and storage investment support mechanisms — are the right primary candidates for delivering the SSEP.

However, we hold the following concerns:

The framework is implicitly a supply-side investment framework. All six levers focus on generation, storage and network. Large flexible new demand — data centres, electrolysers, industrial process heat — is treated as a footnote in Chapter 3 (the AI Growth Zones discussion) rather than as a category requiring its own siting framework. We think this is an omission given that demand-side siting is itself a potentially powerful lever.

Network-readiness for CfDs and other consumer-paid support is itself a lever and warrants explicit recognition. This is set out under Q1b(a) below. Treating it as a sub-component of investment support risks under-stating its importance. Network-readiness conditions are an important consumer-cost lever in the period before the full RNP regime takes effect. They can be introduced for AR8 in 2026 without waiting for the connections regime or locational charging reforms to be settled.

Q 1b) Do you think there are any other levers missing or alternatives that should be considered? If so, please list them and provide rationale and evidence for your suggestion.

We recommend the following missing levers should be added to DESNZ's assessment:

CfD eligibility screening calibrated to optimal economic curtailment

CfD eligibility should be calibrated to optimal economic curtailment given expected network availability. This recognises two things. First, some over-offer of connection capacity relative to the CSNP planning line is essential — to drive competition in CfD auctions (which lowers strike prices and consumer bills) and to absorb project attrition between contract award and commissioning. Many assets need a connection agreement in place before they can bid for support, so the connection regime cannot wait until the network is fully ready before opening the queue.

Second, the over-offer must be bounded by economic optimisation rather than left uncalibrated. Consumer-paid revenue support should not be made available for output that would be uneconomic to curtail. For each technology and zone, there is an optimum point at which the marginal cost of additional expected curtailment equals the marginal value of additional generation. Above that point, additional generation behind a constraint produces more constraint cost than consumer benefit. The current system effectively allows uncalibrated over-offer: NESO projects constraint costs of around £7 billion in 2030/31, and the February 2026 Ofgem letter on TMO4+ Protected Projects shows that 135 of 340 supposedly-protected projects (40%) are now facing network-driven date delays.

The case for treating this as a distinct lever is twofold. First, it can be introduced immediately (AR8, July 2026) without waiting for any of the other levers in the framework to be settled. Second, it is the only lever that operates directly on the consumer-cost-to-developer-revenue interaction. Connections regimes and locational charges shape investment decisions ex-ante, but only CfD eligibility filters control which projects actually receive consumer-paid revenue support.

Independent market monitor with consumer-cost analysis capability

Industry has significantly more resources than the state and consumer representatives to analyse options and shape consultations. We recommend introducing a standing independent market monitor with the capability to publish standardised consumer-cost evidence before decisions are taken. This could improve the reform process, supporting transparent decision-making across DESNZ, Ofgem and NESO. At the moment, there is a risk of institutional fragmentation, alongside growing complexity of the market and policy landscape and the risk of gaming due to suboptimal market design.

Q 2) Do you agree with how we have categorised the levers? Specifically a) in your view, should Network Build, Seabed Leasing and Planning Reform be categorised as enabling levers; and b) in your view should the Connections Regime, Locational Charging and Generation and Storage Investment Support Mechanisms be categorised as primary levers? If no, please provide rationale and evidence for your answers.

We highlight the following issues:

- **Seabed leasing and planning reform are reasonably described as enabling levers.** They create the conditions within which the primary levers operate. The persistent geographic imbalance between Scottish and England & Wales seabed availability has nonetheless shaped the trajectory of AR auctions and is now a material driver of constrained-zone clustering.
- **Network build is different in kind.** The consultation itself acknowledges that "decisions on network planning... will also therefore need to take account of our expectations for likely generation build-out" and that "the date for connections agreements that can be taken up by customers is limited by network build and reinforcement". If network build is shaped by the SSEP Pathway and shapes connection timing, it is functionally equally primary as connections.
- **The consumer-cost evidence is unambiguous.** NESO's projections (February 2026) show constraint costs may peak at around £7 billion in 2030/31, with delivery slippage on key transmission projects potentially pushing the peak materially higher. EGL1 is already 16 months late. NESO has estimated that accelerating Norwich to Tilbury (AENC and ATNC) and Sea-Link (SCD1) from 2031 to 2030 could reduce the 2030 peak by approximately £4 billion. The B6 boundary was constrained in 34% of all hours in 2025.

Under current arrangements, when network build slips, the cost falls overwhelmingly on consumers through BSUoS-recovered constraint payments. Generators with firm CfD contracts continue to receive revenue support. Meanwhile, consumers absorb the constraint cost downstream. The February 2026 Ofgem letter on TMO4+ Protected Projects provides direct evidence: 135 of 340 supposedly-ring-fenced projects (40%) are facing network-driven date delays. Two responses are needed in combination:

Stronger Transmission Operator (TO) accountability for delivery slippage. Ofgem's RIIO-ET3 final determinations include a new connections incentive that rewards meeting and penalises missing connection dates. We welcome this direction but believe the consumer-cost-linked component is not yet calibrated to the scale of the consumer exposure. If a TO's slippage on a specific reinforcement project causes, for example, £500 million per year of additional constraint costs that consumers pay for two years, the TO's exposure should be a material fraction of that £1 billion total.

Network-readiness screening for CfDs should be recognised as a distinct primary lever rather than buried inside investment support — it is the fastest-acting consumer-cost lever in the framework. Demand-side siting levers should be added as a primary lever category. Investment support mechanisms include not just CfDs but also the Capacity Market, the LDES cap-and-floor scheme, the Hydrogen Production Business Model, the Dispatchable Power Agreement, and the interconnector cap-and-floor scheme; the locational dimension should extend across all of them until more effective market-based locational signals are implemented.

Q 3) What are your views on the overall strategic approach we have used for combining the levers into an options framework? For example, the logic and structure underpinning the options including the grid for how to combine the primary levers (Table 1).

No response

Q 4) To what extent do you agree or disagree with the criteria we have used to assess the options? Please provide rationale and evidence to

support your answer with particular reference to any other criteria that could be included in the assessment.

The four criteria proposed by DESNZ — system efficiency, deliverability, investor confidence, and adaptability — are necessary but not sufficient. Three issues need to be addressed to support a robust assessment of the options.

Consumer outcomes should be more prominent

As currently drafted, system efficiency includes "positive impacts on consumers" as one item among several. Consumers are the ultimate funder of the entire system. Their outcomes — bill impact, risk exposure, distributional fairness — should be assessed in their own right. We recommend an Efficiency and Consumer Outcomes criterion that captures efficiency gains with attention to expected bill impacts over time as the system evolves; distributional consequences; the magnitude of inframarginal rents and risk transfers from developers to consumers; and the cumulative consumer benefit available.

Consumer risk allocation should be a distinct criterion

The investor confidence criterion as drafted captures only one side of the risk allocation question. Risk has to sit somewhere. If it does not sit with the investor, it sits with consumers. The risk either sits directly through socialised costs (constraint costs, LAT cover, residual transfers) or indirectly through higher CfD strike prices and CM clearing prices. The current criterion treats this asymmetrically: it counts the cost to consumers of higher risk premia (correctly) but does not count the cost to consumers of socialised risk.

We recommend an explicit “Consumer Risk Allocation” criterion that requires each option to be assessed on:

- who bears delivery risk (the risk that network build lags behind generation);
- who bears modelling risk (the risk that the SSEP Pathway turns out to be partially incorrect);
- and how these risk allocations change over time and can be mitigated.

On weighting and application

“Efficiency and Consumer Outcomes” is the most important criterion because it relates most directly to the policy objective of a lowest-cost, fair delivery of the SSEP (or preferably lowest cost secure and decarbonised power system). It should therefore be weighted more heavily than the others. The other criteria are means, not ends, as they feed into efficiency and consumer outcomes via specific channels rather than mattering in their own right.

- Competition lowers strike prices in CfD auctions and clearing prices in the Capacity Market, which lowers consumer bills directly.
- Investor confidence lowers cost of capital, which lowers strike prices and consumer bills indirectly.
- Consumer risk allocation determines who bears delivery, modelling and political risk; risk that does not sit with the investor sits with consumers via socialised costs (constraint payments, LAT cover) or via higher risk-premia in support contracts.
- Coherence with parallel workstreams determines whether the package as a whole delivers more or less than the sum of its parts.

Efficiency and consumer outcomes therefore warrant a higher weighting. From the consumer perspective, the Consumer Risk Allocation and Coherence criteria are also more important. Deliverability should not be applied as a scoring criterion in its own right because its weight depends entirely on context. A more complex option may be justified if it will be in place for a long period or if it provides an enduring solution that addresses the root cause.

Q 5) Do you agree with our preference for Options 2a, 2b, and 3 being suitable for further development with Options 0, 1 and 4 being discounted? Are there aspects of Options that you either think work particularly well, or that we should consider further? Please provide comments and further evidence to support your answer.

We agree with discounting Options 0, 1 and 4. Of the three options taken forward, our preference is for Option 3 as the durable design, supported by immediate complementary action through CfD screening (the fast lever) to deliver consumer-cost savings ahead of full reform. Option 2b is acceptable only with substantial additional safeguards. Option 2a is the weakest of the three on consumer outcomes.

Option 3 combines connection capacity thresholds set somewhat above the CSNP planning line with a locational charging regime to steer projects toward system-optimal locations. From a consumer perspective:

- It preserves liquidity and competition for CfD support (lower strike prices, lower consumer bills).
- It uses the locational charge to discipline siting within a wider CCT band, addressing the gold rush problem that pure Option 2b would suffer.
- It allows fine-tuning between SSEP iterations as real-world delivery evidence accumulates.
- The locational charging architecture is most easily reconciled with a future move toward LMP.

Q 6) How do you think the risks and disadvantages identified under Options 2a, 2b and 3 (as outlined above in this document) could be addressed?

No response

Q 7a) Do you think it would be practical to set Connections Capacity Thresholds for Options 2a, 2b and 3, by SSEP technology and zone?

No response

Q 7b) How should these thresholds be determined? Please provide rationale to support your answer.

No response

Q 8a) Should we set the CCT at a level higher relative to the CSNP planning line to allow for project attrition and competition in investment support schemes? (i.e. the difference between Option 2a and 2b).

No response

Q 8b) If we set the CCT above the SSEP Pathway, what additional safeguards might be needed to ensure we keep within the SSEP Pathway uncertainty range?

No response

Q 9) What are your views on the role of locational charging, and interactions with our investment support schemes? Note that detailed questions on potential TNUoS and connection charging reforms are covered in Ofgem's recent Call for Input.

Locational charges should reflect the system costs of building generation in different locations that would not otherwise be accounted for by developers. Locational charges send an investment signal — they influence siting decisions at FID — and do not send an operational signal because they are set ex-ante and do not vary with hour-by-hour system conditions.

In a strategically planned system, locational charging can play three useful roles:

- a within-CCT siting signal under Option 3 or 2b (steering projects toward system-optimal locations within the CCT band);
- a within-zone siting signal (capturing intrazonal differences in network usage and constraint exposure);
- and a residual cost-recovery instrument.

A locational network charge is set ex-ante by the regulator and is annualised. It is paid whether or not the asset actually operates in the manner the charge assumed. It cannot vary by hour, by realised constraint, or by direction of flow. For a baseload generator with a stable operating profile, this approximation is tolerable. For storage, interconnectors and flexible demand the approximation is sub-optimal. These resources will do the heavy-lifting in integrating weather-dependent renewables, where the value of the asset is fundamentally about when and whether to import or export relative to local system conditions.

A locational marginal price — set hour by hour at each node or zone, reflecting actual marginal cost — would deliver this operational signal directly. Under the current single national wholesale price, no operational locational signal exists.

We accept that locational marginal pricing was ruled out in the REMA process and we are not asking for that decision to be revisited through this consultation. But the absence of an operational locational signal has consequences this consultation should acknowledge as it limits how much consumer-cost saving the SSEP can deliver. Storage in particular is being asked to respond to a charging regime that cannot price its actual system value. Interconnectors' flows will not support the system as best they could. Flexible demand faces a charging signal that does not vary with the weather and availability of energy locally, nor the constraint conditions they could otherwise help address.

DESNZ should commit to developing the operational locational signal in parallel. This could initially occur through shadow locational pricing from 2027/28 and through locational balancing arrangements where feasible.

The current generation–demand cost split in TNUoS is approximately 16:84. This is not the product of cost-causation analysis. It is a mechanical residual of retained EU Regulation 838/2010 (the Limiting Regulation), which caps the average TNUoS charge paid by generators within the range €0–€2.50/MWh. Historically the GB split was 27:73 by code; from 2014 onward, modifications progressively replaced the code split with a binding cap derived from the €2.50/MWh ceiling. Until the future of the Limiting Regulation is clarified, the basis on which demand pays the great majority of TNUoS is itself unsettled. Whichever Option is chosen, the resulting locational charging design will inherit this constraint.

We urge DESNZ and Ofgem to jointly publish a position on the future of the Limiting Regulation by the end of 2026, as part of the response to this consultation and Ofgem's parallel Call for Input. As retained EU law, the Limiting Regulation can currently be amended or repealed by the UK Parliament.

Q 10) For Options 2a, 2b and 3, what, if any, changes or reforms would be needed to government investment support mechanisms (such as the Contracts for Difference, Capacity Market etc), and if so, what specific reforms would be needed?

We would welcome the publication of the evidence base underpinning the case for change.