Final stage impact assessment

Title:	Electricity Transmission Network Bill Discount Scheme
Type of measure:	Secondary Legislation
Department or agency:	Department for Energy Security and Net Zero
IA number:	N/A
RPC reference number:	N/A
Contact for enquiries:	networksbd@energysecurity.gov.uk
Date:	20/03/2026

Regulatory scorecard for preferred option

Part A: Overall and stakeholder impacts

(1) Overall impacts on total welfare		Directional rating **Note: Below are examples only**
Description of overall expected impact	**Direct Transfers** **A transfer from all electricity consumers to households closest to new transmission network infrastructure** – Funding this policy via a levy on consumer electricity bills will result in a transfer from all electricity consumers to households and communities closest to new transmission network infrastructure. **Direct Costs** **Familiarisation costs** – Licensed Transmission Owners (TOs), and electricity suppliers incur time costs to familiarise themselves with their obligations under the proposed bill discount scheme. **Administration costs** – Government, electricity suppliers and TOs will incur costs to administer community funds and bill discounts. **Non-Quantified Impacts** **Reduced network constraint costs** – If the policy interventions considered in this IA support a reduction in delays to network build, this could reduce congestion on the transmission network and reduce constraint costs, resulting in potential savings for electricity consumers. This is because constraint costs are part of balancing charges, which make up a portion of a household's electricity bill. **Emissions savings** – If this policy supports a reduction in delays to network build and decreases network constraints, there could be emissions savings. This is because when the transmission network is currently constrained renewable generation is usually curtailed (switched off) whilst non-renewable generation is usually switched on to meet demand	**Neutral** **Based on all impacts (incl. non-monetised)**
Monetised impacts	**Total £ Net Present Social Value (NPSV):** -£80m to - £100m **Direct Transfers:** £830m - £1,030m The overwhelming majority of the quantified economic impacts of the policy interventions considered in this Impact Assessment are classified as transfer payments from all electricity consumers to households and communities hosting transmission network infrastructure. Therefore, as these	**Negative** **Based on likely £NPSV**

	transfers net off in aggregate, the net impact on social welfare, as calculated in NPSV is the costs associated with government and industry administration. These costs are considered in more detail in following sections for business and household impacts.	
Non-monetised impacts	**Costs** **Earlier network investment costs –** If this policy supports a reduction in delays to transmission network build, investment could occur sooner than previously planned relative to the baseline scenario. This could result in an increased cost to business, due to increased investment in infrastructure over the appraisal period. This potential impact has not been quantified. **Non-market costs associated with network infrastructure being in place sooner** – If this policy supports a reduction in delays to network build, communities closest to new electricity transmission infrastructure may face non-market costs associated with network infrastructure such as disruption costs, noise impacts, and landscape impacts (this list is not exhaustive), sooner. These costs would still be incurred in the baseline scenario, but they may be incurred sooner if this policy reduces delays to network build. These potential costs have not been quantified. **Benefits** **Spill-over economic & social benefits** –There may be local and regional social and economic spill-over benefits, particularly linked to the provision of voluntary community funds (the counterfactual scenario considered in this Impact Assessment). For example, investment in local social, economic or environmental priority projects may have multiplier impacts in terms of generating local employment opportunities and enduring local benefits for host communities. **Shorter network connection times for new low carbon generation** – Enabling works must be completed before a new generation or demand asset can connect to the electricity transmission network. If this policy supports a reduction in delays to network build including enabling works, this could allow new low carbon generation assets to connect to the network more quickly, supporting households and businesses across the country in achieving cheaper, more secure and low carbon energy generation. **Greater buy-in to the energy transition** – This policy aims to ensure communities are involved and considered in the energy transition, which may increase buy-in. **Potential supply chain benefits** – If this policy reduces delays to network build, there may be supply-chain benefits for TOs and developers if they are able to access materials sooner.	**Positive**

	Lower legal costs –Communities closest to new infrastructure may have lower legal costs due to this policy if they feel they are benefitting adequately from transmission network infrastructure being sited within their community and are do not feel obliged to legally challenge the granting of consent for construction of the infrastructure as a result.	
Any significant or adverse distributional impacts?	The policy interventions considered in this Impact Assessment constitute transfers from all electricity consumers to households and community organisations in areas of Great Britain hosting new and significantly upgraded transmission network infrastructure, so by design will have distributional impacts. However, due to data limitations, it has not been deemed proportionate to attempt to quantify the net equity weighted impact of re-distribution. Therefore, the overall distributional impact of the policy interventions considered is uncertain. Further discussion of the initial assessment of the potential distributional impacts of the policies considered can be found in section 12 of the evidence base "Other wider impacts"	**Uncertain**

(2) Expected impacts on businesses		
Description of overall business impact	**Summary:** Businesses (voluntary and community organisations) are classed as the primary beneficiary of the counterfactual scenario (community funds). The additional policy options considered (bill discount scheme) constitute additional burden on businesses in the form of contributing to funding of the levy and fulfilling administrative obligations. These impacts broadly net out in our cost-benefit analysis, leaving a marginally positive Business Net Present Value (BNPV). If the policy is successful in fulling its stated objectives it may create an environment more supportive of transmission network infrastructure development which would be of benefit to licenced transmission owners and businesses seeking to connect to the transmission network – though this has not been quantified. **Costs to fund the scheme:** All energy consumers (including businesses) will pay a policy cost to fund both schemes considered in scope of this Impact Assessment. Businesses are not eligible to receive a bill discount payment and so this represents an overall transfer from businesses to households. **Industry administration costs:** Licenced electricity suppliers will incur costs to deliver the bill discount scheme to eligible households which they supply. They will also incur costs to collect funds from all consumers and from participating in the reporting and reconciliation process. It is anticipated that these costs will be passed on to their customer bases. **Familiarisation: Licenced** electricity suppliers and Transmission Owners (TOs) will incur costs to familiarise	**Neutral**

	themselves with their obligations under the proposed bill discount scheme. **Benefits - Direct Transfers:** In the counterfactual scenario (voluntary community funds for transmission network infrastructure) the benefits of transfer payments are expected to benefit households in communities hosting transmission infrastructure, albeit indirectly, therefore for reporting purposes in this impact assessment they are classified as benefit to business, which includes voluntary and community organisations.	
Monetised impacts	Business NPV: **£10m – £20m** **Costs** Transfers from businesses (voluntary community funds): **£325m – £385m** Transfers from businesses (bill discount scheme): **£145m - £185m** Transmission Owner administration costs (pass through to businesses): **£30m - £40m** Electricity supplier administration and familiarisation: **£4m - £5m** **Benefits** Transfers to businesses (voluntary community funds): **£525m - £625m** Estimated Annual Net Direct Cost to Business (EANDCB): **£1.8m** We assume that supplier administration costs will be passed onto energy consumers (both business and household). These are modelled on consumer bills in Sections 6 and 7 but have not been deducted from the costs here	**Neutral** **Based on likely business £NPV**
Non-monetised impacts	It is anticipated that provision of a defined benefit, either collectively to the community (Option 0: voluntary community funds) or in the form of direct transfers to individual households (Options 1-3: bill discount scheme) may improve community engagement in the various stages of transmission network infrastructure development and therefore contribute to the wider government objectives of supporting an accelerated deployment of critical transmission network infrastructure. There are potentially significant indirect benefits associated with the scenario where these policy interventions are successful in supporting these objectives, with accelerated deployment and the avoidance of delays to planned network build likely to yield significant reductions in network constraint costs, relative to the scenario where delays persist. However, the extent to which these policies may	**Uncertain**

	support these potential benefits has not been quantified. See section 5.4 of evidence base outlined in this Impact Assessment for further details.	
Any significant or adverse distributional impacts?	The direct costs of both the counterfactual and policy options considered in this appraisal are incurred by licenced Transmission Owners (TOs) and electricity suppliers. In the counterfactual scenario (voluntary community funds) TOs solely incur costs, associated with their administrative responsibilities, for which they are able to pass on costs of up to 10% of fund values. In the proposed bill discount scheme policy scenario both TOs and electricity suppliers are likely to incur costs associated with their roles and responsibilities to enable the scheme to function, although it has only been deemed proportionate to quantify administrative costs incurred by electricity suppliers. By facilitating transfer payments there is a potential risk that some electricity suppliers, particularly those with smaller market shares could be exposed to negative cashflow risk, particularly if their customer base are disproportionately represented in the population of eligible residential properties. However, without access to Meter Point Administration Number (MPAN) data it has not been possible to link eligible Unique Property Reference Numbers (UPRNs) identified in our analysis to current electricity suppliers and therefore it has not been possible to assess the extent to which this risk is material. Potential mitigations considered include considerations about the process and timings for reconciliation of funds, and amount of notice provided to suppliers to amend billing processes and collect funds in advance.	**Uncertain**

(3) Expected impacts on households		
Description of overall household impact	Summary: Households within 500m of qualifying transmission network infrastructure are the primary beneficiary of the proposed bill discount scheme assessed in this Impact Assessment. Although households within communities hosting transmission network infrastructure are likely to be the ultimate beneficiaries of transfer values in the counterfactual scenario, they do so indirectly because the projects funded are delivered via voluntary/community organisations which are classed as businesses. All other electricity consuming households will proportionally fund the proposed policy options considered. The net impact on households collectively is the two sets of transfers broadly balance each other out, albeit with a marginally negative household NPV. This is due to the estimated value of transfers for community funds, which is allocated to voluntary and community organisations	**Neutral**

	(businesses) in this IA outweighing the estimated value of transfers for the bill discount scheme. There are potentially significant non quantified impacts, associated with reduced transmission network constraint costs, which could positively impact households via reduced balancing charges, however, this impact is uncertain and not quantified.	
Monetised impacts	Household NPV: **- £80m** **Costs:** Transfers from households (voluntary community funds) **£200m - £240m** Transfers from households (bill discounts) **£75m – £95m** Transmission Owner administration costs (pass through to households) **£20m – £25m** **Benefits:** Transfers to households (bill discounts) **£215m - £280m** Estimated Annual Net Direct Cost to Households (EANDCH): **£9.0m** We assume that supplier administration costs will be passed onto energy consumers (both business and household). These are modelled on consumer bills in Sections 6 and 7 but have not been deducted from the costs here.	**Neutral** **Based on likely household £NPV**
Non-monetised impacts	There are potentially significant indirect benefits associated with the scenario where these policy interventions are successful in supporting an accelerated deployment of critical transmission network infrastructure and the avoidance of delays to wider transmission network. If this scenario materialises it is likely to yield significant reductions in network constraint costs, and therefore end consumer bills, relative to the scenario where delays persist. The potential benefit of this acceleration scenario for a typical domestic consumer has been quantified by Ofgem in their RIIO-3 Impact Assessment at £55 in 2030/31.[1] However, the extent to which these policies may support these potential wider benefits is uncertain and therefore has not been quantified. See section 5.4 of evidence base outlined in this Impact Assessment for further details.	**Uncertain**
Any significant or adverse distributional impacts?	The policy interventions considered in this Impact Assessment constitute transfers from all electricity consumers to households and community organisations in areas of Great Britain hosting new and significantly upgraded transmission network infrastructure, so by design will have distributional impacts. However, due to data limitations, it has not been	**Uncertain**

[1] Ofgem (2025): RIIO-3 Final Determinations – Impact Assessment

	deemed proportionate to attempt to quantify the net equity weighted impact of re-distribution. Therefore, the overall distributional impact of the policy interventions considered is uncertain.	

Part B: Impacts on wider government priorities

Category	Description of impact	Directional rating
Business environment: **Does the measure impact on the ease of doing business in the UK?**	The policy interventions considered in this Impact Assessment will introduce new administrative and compliance burdens on licenced transmission owners and suppliers of domestic meter points in the GB electricity market. However, if the policies deliver on their intended	**Uncertain**
International Considerations: **Does the measure support international trade and investment?**	The policy options considered in this appraisal are not anticipated to have any significant trade implications given the relate predominately to transfers from all electricity consumers to households and communities in areas of Great Britian hosting new transmission network infrastructure.	**Neutral**
Natural capital and Decarbonisation: **Does the measure support commitments to improve the environment and decarbonise?**	The policy option considered in the counterfactual scenario may support local investments in natural capital, however, this is at the discretion of local communities and the relevant transmission owners and has not been quantified. The additional policy options considered may have an indirect impact on eligible household energy consumption, as a result of comfort taking, which could have emissions implications, however, this is not an intended impact of the policy intervention and has not been quantified. If the package of policy interventions considered in this IA fulfil their stated objectives and contribute towards an accelerated deployment of transmission network investment this may have a positive impact on decarbonisation as the transmission network is a critical enabler of the government Clean Power 2030 and Net Zero 2050 targets.	**Neutral**

Declaration

Department:

Department for Energy Security & Net Zero

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Minister:

Michael Shanks

I have read the Impact Assessment, and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed: 

Date: 20/03/2026

Summary: Analysis and evidence

Price base year: 2025

PV base year: 2026

Policy Option	**0.Do-minimum** **(counterfactual)**	**1.Less ambitious intervention**	**2. Preferred way forward** **(if not do-minimum)**	**3. More ambitious intervention**
Policy Description	Voluntary Community Funds Guidance. Non-regulatory intervention.	Voluntary community funds, and proposed bill discount scheme with reduced scope of eligible qualifying works.	Voluntary community funds, and proposed bill discount scheme.	Voluntary community funds, and proposed bill discount scheme with expanded scope of eligible qualifying works.
Net present social value[2] (with brief description, including ranges, of individual costs and benefits)	**£(-65m) - £(-50m)** **Transfers** Transfer from all energy consumers to eligible organisations: **£545m - £650m** **Costs** Transmission Owner administration and delivery costs: **£50m - £60m**	**£(-100m) - £(-75m)** **Transfers** Transfer from all energy consumers to recipients through the bill discount scheme and voluntary community funds: **£770m – £940m** **Costs** Industry Administration Costs: **£55m - £65m** of which,	**£(-100m) - £(-75m)** **Transfers** Transfer from all energy consumers to recipients through the bill discount scheme and voluntary community funds: **£810m – £985m** **Costs** Industry Administration Costs: **£55m - £65m** of which,	**£(-100m) - £(-80m)** **Transfers** Transfer from all energy consumers to recipients through the bill discount scheme and voluntary community funds: **£820m– £995m** **Costs** Industry Administration Costs: **£55m - £65m** of which,

[2] Estimated NPSV, Transfers and Costs have been rounded to the nearest £5m or £1m where appropriate.

		Transmission Owners: £50m - £60m Electricity Suppliers: ~£5m Government administration costs: **£20m – £35m** Industry Familiarisation costs: **~£1m**	Transmission Owners: £50m - £60m Electricity Suppliers: ~£5m Government administration costs: **£20m – £35m** Industry Familiarisation costs: **~£1m**	Transmission Owners: £50m - £60m Electricity Suppliers: ~£5m Government administration costs: **£20m – £35m** Industry Familiarisation costs: **~£1m**
Public sector financial costs (with brief description, including ranges)	N/A		Government will incur costs to implement and administer the scheme. These costs can be broadly split into two categories: **Set up/implementation costs:** Resource and capital expenditure funded by DESNZ for the period 2025 – 2026, to develop the scheme and establish a formal monitoring and evaluation programme. **Business as Usual delivery costs:** These are based on the preferred scheme administrator's initial assessment of the potential ongoing costs to facilitate the scheme. Certain defined costs incurred by the scheme administrator in the delivery phase of scheme would be recouped via the levy on consumer bills, whereas all other costs to government associated with implementation would be covered by existing departmental budgets. The total estimated costs to government are assumed to be broadly equivalent across Options 1 – 3 **Total government administration costs:** £22m - £33m of which; **Cost to government:** £11m - £16m **Passed onto consumers:** £11m - £17m	
Significant un-quantified benefits and costs (description, with scale where possible)	It is anticipated that provision of a defined benefit, either collectively to the community (Option 0) or in the form of direct transfers to individual households (Options 1-3) may improve community engagement during the various stages of transmission network infrastructure development and therefore contribute to the wider objectives of supporting an accelerated deployment of critical transmission network infrastructure. There are potentially significant indirect benefits associated with the scenario where these policy interventions are successful in supporting these objectives, with accelerated deployment and the avoidance of delays to planned network build likely to yield significant reductions in network constraint costs, and therefore end consumer bills, relative to the scenario where delays persist.			

Key risks (and risk costs, and optimism bias, where relevant)	Due to known interactions with the ongoing TM04+ grid connection reforms it has not been deemed proportionate to carry out an exhaustive assessment of all potentially eligible enabling works within the appraisal period considered for this intervention, as the scope and scale of enabling works required is likely to be materially different upon the conclusion of grid connection reforms. Therefore, there is a potentially significant risk across all options considered, but particularly the counterfactual (Option 0), preferred way forward (Option 2) and more ambitious intervention (Option 3) that this appraisal underestimates the scale of transfer values incurred. Further assessment of potential scheme costs will be carried out ahead of proposed scheme go-live date in the second half of 2026 when more public data on the potential scale of qualifying enabling works should be available. Ongoing monitoring and evaluation of scheme costs is factored into the existing evaluation programme, including a formal post-implementation review point 5-years after scheme launch.

Evidence base

1. Problem under consideration, with business as usual, and rationale for intervention

1. At the heart of the government's agenda is an ambition to make Great Britain (GB) a clean energy superpower, with twin objectives of delivering clean power by 2030 and accelerating towards net zero to boost energy independence, protect consumers, and support jobs. Key to achieving this is ensuring that the electricity transmission network, which transports electricity from where it is generated to where it is needed, is fit for purpose. As we increase low-carbon and renewable electricity generation, we will need to increase the scale of the transmission network, at pace, to keep up with demand and reduce the impact of constraints in the existing network. Rapid expansion is therefore required - around twice as much new transmission network infrastructure will need to be built by 2030 as has been built in the past decade.[3]

2. However, public consent for new transmission network infrastructure projects is precarious and challenges the government's ability to meet the required scale of infrastructure to keep pace with increasing electrification and to help realise clean power by 2030 targets, as it can be challenging for communities to visualise the positive externalities for all consumers from this investment when faced with the localised negative externalities associated with permanent, visually impactful infrastructure. Community opposition increases the potential risk of legal challenges to planning consents, potentially resulting in delays to the approval and development of new transmission network infrastructure.

3. According to data from the DESNZ Public Attitudes Tracker, 79% of people said they were aware of the need to build more electricity network infrastructure, but respondents were more likely to be unhappy (30%) than happy (23%) about the prospect of new electricity network infrastructure being built in their local area.[4] These results are similar to findings from DESNZ-commissioned social research, which indicated that around 10% of respondents find the construction of infrastructure in Great Britain unacceptable, with this figure rising to 24% - 30% when the proposed infrastructure would be constructed in their local area.[5] However, findings from this social research suggested that a community benefit approach of electricity bill discounts was able to increase acceptance for new transmission infrastructure for the most respondents (78%), including more than two thirds (69%)

[3] National Energy System Operator (NESO): Advice on achieving clean power for Great Britain by 2030

[4] DESNZ (2024): Public Attitudes Tracker: Summer 2024. A substantial proportion of respondents provided a more neutral answer, either stating they did not mind either way (34%), or that they did not know enough to form an opinion (6%) or that it wouldn't be feasible in their local area (7%).

[5] BMG Research (2024) – Community benefits for electricity transmission network infrastructure. Q: "How acceptable or unacceptable would you find [a substation/a lattice pylon] being built within a 15-minute walk from your home? And Varian UK (2024) - Public attitudes to network infrastructure: an online experiment testing rationales for building new network infrastructure. Q: "How acceptable or unacceptable would you find the construction of new electricity infrastructure in your local area?"

of respondents who previously stated that transmission network infrastructure projects in their local area would be unacceptable.[6]

4. Communities that host network infrastructure are a critical support in delivering cheaper, cleaner, secure energy – there is a positive externality for wider society. Without government intervention, these external benefits are unlikely to be considered, leading to under-provision of network infrastructure. Government intervention is required to internalise this external benefit and ensure communities can gain from hosting network infrastructure that delivers a national need. Two forms of government intervention to address this goal are explored in greater detail in this Impact Assessment. In March 2025, the government took the first step in publishing voluntary guidance for the provision of community funds linked to transmission network infrastructure.[7] Government also announced its intention to intervene further to create a bill discount scheme, which would be established through powers provided by the Planning and Infrastructure Act.[8] This forms part of a dual approach to ensure that communities can directly benefit from hosting clean energy infrastructure, as recommended by the independent Electricity Network Commissioner.[9]

5. Community Funds are expressed as the counterfactual scenario in this Impact Assessment for appraisal purposes because they are a non-regulatory intervention already in place and do not require legislation. This does not imply that community funds are withdrawn or replaced by the bill discount scheme. Under the government's preferred approach, they continue alongside it as a complementary measure. Together, they form the Community Benefits package for transmission infrastructure.

2. Policy objective

6. The scheme's primary aim is to recognise the role communities play in supporting the accelerated delivery of cheaper, secure and low-carbon energy that benefits the entirety of Great Britain. Additionally, the provision of direct benefits may support improved community engagement on transmission network infrastructure projects, which in turn could support the wider package of reforms designed to accelerate deployment of network infrastructure, as outlined in the Clean Power Action Plan.[10] If this acceleration scenario is achieved, analysis by NESO and Ofgem suggests this may yield significant network constraint costs savings for all electricity bill payers, relative to the scenario where delays to network build persist.[11]

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[6] DESNZ (2024): Research and analysis - Community benefits for electricity transmission network infrastructure.

[7] DESNZ (2025): Guidance: Electricity transmission network infrastructure - Community funds

[8] DESNZ (2025): Electricity transmission infrastructure: proposed bill discount scheme

[9] DESNZ (2023): Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations

[10] DESNZ (2024): Clean Power Action Plan: A new era of clean electricity

[11] This is explored in further detail in Section 5.4, Non-Quantified Benefits.

7. These overarching policy objectives would be realised through the following project objectives.

Project Objectives:

A. **Recognition of host communities**: as outlined in the Clean Power Action Plan (Dec 2024), the government is keen that communities who host clean energy infrastructure should benefit from it. This bill discount scheme aligns with this principle by recognising communities who host new transmission infrastructure that is vital for our clean energy ambitions.
B. **Improving community acceptability**: over the duration of the scheme, ensure eligible recipients understand: the direct economic benefit they are receiving; how they will receive the benefit; when they will receive the benefit – eligible recipients will receive the benefit once construction starts for eligible projects post scheme launch in 2026, to show a clear link between new transmission infrastructure in their vicinity and an individual, direct benefit. It is anticipated that this provision of a direct financial benefit would facilitate improved community engagement and acceptability of the new infrastructure. The extent to which this is the case will be tested in the proposed monitoring and evaluation programme, through baseline evaluation and surveys.
C. **Delivery of automatic benefits**: ensure that as many of the properties eligible for the scheme receive the automatic discount promptly through their energy supplier for the scheme's duration.
D. **Opt-in recipients**: ensure that the properties that cannot receive the discount automatically, can enrol and receive the discount promptly through the opt-in route.
E. **Ensure alignment of experience across the scheme**: as far as possible, align household experiences of the scheme across GB and across both the automatic and opt-in schemes to ensure consistency. Minimise potential negative impacts through monitoring of disbenefits.
F. **Ensure wider public knowledge of the scheme**: throughout the duration of the scheme, ensure the broader public understands the economic, social, and environmental benefits of the bill discount scheme, benefitting all of GB. Namely: the need to bring communities along to expand the grid, how this could reduce delays and constraint costs and increase emissions savings.

8. The proposed scheme is not intended to compensate for infrastructure impacts. While there are concerns about house prices, evidence is mixed: Research from the London School of Economics suggests reduced visual amenity can have a significant impact on property values, estimated at an average reduction of 3.6% for properties within 1,200m of transmission network infrastructure.[12] A Scottish Renewables report found contrasting results; that house prices along the Beauly-Denny power line in Scotland align with trends within the wider local authorities and are therefore more likely to be influenced by macroeconomic factors than proximity to infrastructure.[13] Linking benefits to homeownership excludes many who rent, and basing the scheme on compensation creates complexity where 'impact' is subjective and multifaceted.

[12] Tang and Gibbons (2024), Are friends electric? Valuing the social costs of power lines using house prices, Energy Economics, v.134 June 2024
[13] Scottish Renewables (2024) House Prices: Impact of Beauly-Denny Grid Infrastructure. A BiGGAR Economics Report to Scottish Renewables

Instead, the scheme is focused on building a positive culture around new transmission infrastructure, through recognition of the role local communities in hosting this critical infrastructure.

3. Description of options considered

3.1. Long list of options

9. **Option A: Do nothing** – Community benefits for transmission network projects continue to be provided on an inconsistent, ad-hoc basis. There is an existing process for landowners who host infrastructure to receive direct payments through wayleaves or easements to compensate them for use of their land, which is not considered in scope of this appraisal as there are no proposed changes. TOs have also previously had funding approved by Ofgem in previous price control periods for Consumer Value Propositions (CVPs) that deliver social and environmental benefits to consumers in their licence area beyond the minimum regulatory provisions. Previous funding for CVPs has been on an inconsistent basis and was not explicitly linked to individual transmission infrastructure projects being delivered.[14] Following the government's public commitment, a handful of Accelerating Strategic Transmission Infrastructure (ASTI) projects have had community benefit funds receive regulatory approval in anticipation of central government guidance being published at a later date, these include the Eastern Green Link, offshore transmission projects and an onshore overhead line project in Yorkshire.[15] It is worth noting that given the limited public data concerning CVPs and the signalling impact of government intervention a formal quantification and cost-benefit analysis of a true "Do nothing" scenario has not been deemed proportionate, instead, the "Do Minimum" scenario is considered as the formal counterfactual for policy appraisal.

10. **Option B: Counterfactual "Do Minimum" - Voluntary guidance** (Non-Regulatory Approach): Publish voluntary guidance for the type and level of community benefit that should be provided to host communities. Guidance was published by DESNZ in March 2025 setting out the framework for TOs to voluntarily deliver this option.[16] It is anticipated that TOs will likely distribute funds through either a community grant model, or a regional investment model. The guidance does not prescribe what the funds should be spent on, recognising that each community would likely have its own individual priorities, however, initial feedback from stakeholders suggests funds would likely be used to invest in projects that support energy efficiency, social infrastructure, environmental enhancement and skills development, to deliver long-term local impact. It is anticipated that the funds are unlikely to be used to deliver bill discounts due to the complexity in delivering with no central body. This is the counterfactual scenario any further policy intervention is assessed against

[14] For instance, Scottish Power Energy Networks (SPEN) delivered a £20m Green Economy Fund in their licence area, with funds approved by Ofgem in RIIO-1. See Green Economy Fund – Final Report 2021 for further details.
[15] See Eastern Green Link 1 – Project Assessment sections 3.16 – 3.23, Eastern Green Link 2 – Project Assessment section 2.6, and Yorkshire Green – Project Assessment section 2.5
[16] DESNZ (2025) Guidance - Community funds for transmission infrastructure

11. **Option C: Electricity bill discount scheme** – An electricity bill discount would be delivered to properties within an eligible radius of proposed new infrastructure. This is the government's current minded to position, as outlined in a policy statement in March 2025 and a subsequent public consultation on scheme design in August 2025. This option is considered and presented as an additional intervention on top of the existing community benefit provision outlined in the counterfactual (Option B: Do Minimum). The principle of a central mandated and administered transfer payment – facilitated through an obligation on electricity suppliers - is considered in the long-list appraisal, with further sub-options explored in detail in the shortlist appraisal.[17]

12. **Option D: Electricity bill discount scheme, with alternative funding arrangements –** Same policy option as Option C above but exploring alternative mechanisms for the recovery of scheme costs, such as on a per metered basis or via exchequer funding.

13. **Option E: Direct payment scheme** – A direct payment delivered to residential properties close to proposed new transmission network infrastructure. This option is considered as an alternative delivery model to Option C. It is assumed that this option would be delivered directly by each of the licenced TOs, without the need for a central administrator. This is the delivery model for the closest international comparison to the preferred policy option, which is explored in more detail in subsequent sections.

14. Additional long-list options which have been ruled out on viability grounds:[18]

15. **Option F: Extending eligibility of the proposed bill discount scheme to all existing transmission network infrastructure.** Households within proximity of existing infrastructure have not been considered in scope of the proposed intervention as the intention of the scheme is to recognise the role communities currently unaffected by transmission infrastructure will play in supporting the Clean Power by 2030 mission. Due to the unprecedented increase in network build required, the government believes it is right that those who will host new electricity transmission network infrastructure directly benefit. As a by-product of our analysis of the preferred policy option, we have modelled an approximate number of households extending the scope of the scheme to all existing transmission network infrastructure may bring into scope and estimate that this could lead to a potential nine-fold increase, with a broadly equivalent increase in the costs of the scheme.[19]

[17] Public minded to position, as published in March 2025 of £2,500 over 10 years to residential properties within 500m.

[18] These have not been formally included in the long-list appraisal table due to space constraints but a description of why these have been excluded from short-list appraisal is provided.

[19] Transfer payments account for approximately 95% of all scheme costs in the preferred option.

16. **Option G: Undergrounding of all new transmission network infrastructure.** A common point raised by campaign groups and communities opposed to hosting transmission infrastructure is a preference for new transmission infrastructure to be built underground, to mitigate the visual amenity impacts of overhead lines.[20] This option has not been considered further as the planning process for transmission network projects operates independently of the Government. Transmission Owners, Ofgem and the National Energy System Operator (NESO) are best placed to determine and pursue the most cost-efficient solutions and do so in line with the principles set out in the Holford rules and the National Policy Statement for electricity network infrastructure (EN-5).[21,22] Furthermore, while the exact cost-benefit trade-offs for the choice of appropriate solution will vary on a project-by-project basis, recent evidence from the Institute of Engineering and Technology (IET) suggests that the costs of undergrounding are typically 4.5 times higher than an equivalent overhead line route.[23]

3.2. Critical Success Factors

17. The criteria for assessing the viability of long-list options included:
    - **Strategic fit**: the policy option's likelihood of improving community acceptability of transmission infrastructure. The assessment of long and short list policy options is mostly based on qualitative judgements, supported by evidence from DESNZ funded social research and a wider body of existing academic research.
    - **Potential affordability/cost/ value-for money:** to minimise the impact on consumer electricity bills who ultimately fund the policy options considered. Assessed as a mix of qualitative judgements and quantification for long-list options and formal cost-benefit analysis for shortlisted options.
    - **Potential achievability/ risk profile**: particularly the risk of the policy being applied inconsistently, and any fraud risk associated with distribution of funds to ineligible properties. Assessment predominantly based on qualitative judgements, supported by advice from key stakeholders such as, licenced electricity suppliers and transmission owners, and the electricity market regulator.
    - **Perceived fairness**: How policy design options may result in different outcomes for certain affected groups, particularly those at the boundaries of the proposed scheme and those with characteristics covered by the public sector equality duty. Assessment predominantly based on qualitative judgements.

3.3. Analysis of Long – listed Options

18. Long-list appraisal involved internal DESNZ colleagues, although has also been informed by regular stakeholder engagement with potentially impacted parties and a

[20] See examples referenced in Onward (2023): Power to the People: How to unlock energy infrastructure by securing community support, p27.
[21] The Holford Rules
[22] National Policy Statement for electricity networks infrastructure (EN-5)

[23] Institution of Engineering and Technology (2025): A comparison of electricity transmission technologies: Costs and characteristics

feasibility assessment carried out by Cambridge Economic Policy Associates (CEPA) for the department in 2023.

Table 3.1: Long List Options Appraisal

	Option A	Option B	Option C	Option D	Option E
Option name	Do Nothing	Do Minimum (Community Funds)	Bill Discount Scheme	Bill Discount Scheme (Alternative Funding)	Direct Payment Scheme
Description	Status quo – inferred from previous price control periods.	Non-regulatory option (Counterfactual)	Government published minded to position.	Alternative funding mechanism	Alternative delivery mechanism.
Scope: eligible population	Funds allocated to communities within TO licence area.	Funds allocated to host community	Funds transferred directly to eligible residential households		Funds transferred directly to eligible residential households
Service solution/ delivery	TOs allocated funds in respective licence area, either directly or via third parties. No consistent formula for calculating appropriate amounts. Given regulatory uncertainty of approval participation expected to remain ad-hoc.	TOs allocate funds to communities in respective licence area, either directly or via third parties, with funding pot calculated from a set rate per km of OHL or asset (substation) installed – as set out by government guidance and regulatory approval guaranteed.	Additional funds transferred directly to eligible residential households. Facilitated by electricity supplier obligation, overseen by central scheme administrator.		TOs would be responsible for allocating funds directly to eligible households identified. Would require changes to guidance and change in appetite for delivery among key stakeholders.
Funding	Funding for consumer value propositions put forward by TOs each price control period and subject to approval by Ofgem – with no guidance and varying outcomes as evidenced over RIIO-1 and RIIO-2.	TO funding for an aggregate community fund pot approved for price control period, with funding formula pre-approved via government guidance and ultimately paid for by domestic and non-domestic customers via network charges.	Supplier obligation, ultimately passed through to electricity consumers. Charged on volumetric basis and ultimately funded by all domestic and non-domestic customers.	Two alternative options were considered. (i) Supplier obligation as Option C, but with funds charged on the basis of meter points served rather than volume of electricity supplied. (ii) Exchequer funding, requiring either	Same mechanism as for Option B – but would require changes to the guidance and additional funds

				increasing in taxation or borrowing.	
Strategic fit/ timing	**Low**: Host communities unlikely to see direct, tangible benefits associated with transmission infrastructure works in their local area – where funding is approved, likely to be applied inconsistently across GB.	**Medium-High**: Ensures host communities see direct, tangible benefits associated with transmission infrastructure works in their local area. Guidance published March 2025 with TOs ready to deploy funds from financial year beginning April 2026. 60% of respondents in social research indicated that this type of intervention would increase their acceptance of transmission infrastructure in their local area. Including 48% of those initially opposed.	**High**: Ensures host communities & individual households see direct, tangible benefits associated with transmission infrastructure works in their local area. Ambitious delivery timeline has scheme-go live as October 2026, with first payments following in early 2027. 78% of respondents in social research indicated that this would increase their acceptance of transmission infrastructure in local area. Including 69% of those initially opposed.		**Medium**: Ensures host communities & individual homeowners see direct, tangible benefits associated with transmission infrastructure works in their local area. Fundamental change in delivery model which would require further policy development and stakeholder engagement, delaying roll out. 63% of respondents in social research indicated that this would increase their acceptance of transmission infrastructure in their local area. Including 56% of those initially opposed.
Potential achievability/ risk profile	**Medium-Low**: High achievability (as no change to status quo) but high risk of reputational damage, given significant increase in infrastructure projects to facilitate	**High:** Guidance is already published with TOs preparing to distribute funds from FY 2026/27. Likely lower risk of unintended consequences highlighted for direct delivery of benefits to individuals (i.e., as in Options C and D) due to provision of	**Medium**: Likely complexity in data sharing processes and administration. Social research evidence from other similar interventions in alternative contexts suggests potential risk of unintended consequences if transfer values deemed too low and/or are negatively framed by host communities, or if fixed distance eligibility criteria creates division and poor engagement with host communities.		**Low**: Subject to same potential risks of unintended consequences associated with the distance criteria as option C. Further risks with framing, with social research highlighting potential

	clean power targets.	benefit to community, with no fixed proximity boundary and flexibility for TOs and communities to define and collaboratively decide who benefits from the funds.			negative framing of payments from developers among eligible communities as bribes.[24] Deliverability of this option is dependent on key stakeholder agreement which is understood to be unlikely.
Potential affordability	**Not quantified:** Assume no additional cost.	**Total Transfer Value:** £545m - £650m **Aggregate cost per average domestic consumer:** £8.50 - £10.10 Confidence in estimate: Medium	**Total Transfer Value[25]:** £770m - £995m **Aggregate cost per average domestic consumer**: £11.80 – £15.20 Confidence in estimate: Low[26]	For alternative option (i) levy funded on a per metered basis, the average cost per consumer would be equal for both domestic & non-domestic consumers. As domestic properties account for approx. 92% of meter points but only ~37% of electricity consumption this would result in an approximately x3 fold increase in cost for a typical domestic electricity consumer, relative to the preferred option. Funding the scheme via the exchequer (alternative funding option ii) would require an	**Not quantified**: Some design elements, particularly if mirroring the EirGrid example discussed below could potentially lead to a lower cost option. Others would imply a higher cost.

[24] For instance, Cass et al. (2010); Walker et al. (2015) This theme was also referenced in DESNZ commissioned social research, referenced above, with 37% of respondents who were resistant to any form of intervention improving their acceptance of transmission infrastructure, stating a perception of "bribery" as the main reason for this.

[25] Transfer and cost values for Option 2, should be interpreted as the absolute cost inclusive of the do minimum/counterfactual scenario (option 1) unless explicitly stated otherwise.

[26] The confidence in transfer & cost estimates is low for Option C: Bill Discount Scheme, due to the uncertainty associated with the lack of quality geospatial data available on infrastructure projects identified as eligible in this appraisal, in addition to the underlying uncertainty in the project pipeline which impacts all options – see Section 13. Risks and assumptions for further details.

				increase in taxation or government borrowing, which has not been deemed to be likely to be approved, following engagement with officials at HM Treasury.	
Supplier capacity and capability	**High:** TOs have previous experience in delivery of consumer value propositions – this would be no change in their role.	**Medium-High**: TOs have previous experience in delivery of consumer value propositions and already have direct contact with impacted communities, through routing and consenting process.	**Medium**: Electricity suppliers and scheme administrator have previous experience of passing on funds in this role, with EBSS and WHD, but geospatial factor brings added complexity. A sufficient period of notice would typically be needed for suppliers to account for adjustments in pricing and billing processes.		**Low**: TOs have previous experience in settling compensation agreements for landowners directly hosting transmission infrastructure, but this would be a significant extension of their role – with previous engagement suggesting limited appetite for it, given potential for unintended consequences associated with negative framing.
Perceived fairness/ procedural justice/equity	**Low**: Majority of host communities experience little to no direct benefit from infrastructure projects.	**Medium:** As funding provision is in aggregate to the community rather than directly to individual eligible households, this is likely to be perceived by host communities as an allocation with higher levels of procedural justice relative to other policy options considered in this appraisal. However, lack of targeting at households most likely to be impacted by the	**Medium**: A more targetted form of intervention than the counterfactual, however, the use of a fixed distance as a qualifying criterion risks unintended consequences at the boundaries, with potential consequences for perceived procedural	**Medium/Low:** Option A: per metered approach to cost recovery, dependent on relative value judgement and equity weights applied to domestic & non-domestic consumers. Comparing within consumer groups though – a volumetric approach (preferred option) is likely to be more progressive. Option B:	**Medium**: A more targetted form of intervention than the counterfactual , however, the use of a fixed distance as a qualifying criterion risks unintended consequences at the boundaries, with potential consequences for perceived procedural justice by host communities.

		infrastructure could be interpreted as a diluting of potential benefits.	justice by host communities.[27]	Exchequer funding is understood to be likely more progressive than levying the costs on electricity bills, however, this option has not been considered feasible.	
Potential Value for Money	N/A	**Uncertain:** Any indirect benefits associated with accelerated transmission network deployment conditional on intervention improving community engagement and interaction with other delivery risks (supply chains, skills etc.). Uncertainty in causal chain, makes judgements on benefit realisation highly uncertain.			
Summary	Discontinued	**Shortlist (Counterfactual)**	**Shortlist (Preferred)**	**Discontinued**	**Discontinued**

3.4. International Comparisons

19. The nearest international comparison to the proposed policy position is the proximity payment policy overseen by EirGrid, the Transmission System Operator (TSO) for the Republic of Ireland.[28] The design elements of the EirGrid proximity payment scheme offer an insight into a potential alternative provision of the core aims and objectives of the current government minded-to-position. Key differences in policy design includes the payment rate and structure, eligibility criteria, and delivery model. These differences are outlined in Table 3.2 below.

Table 3.2: International Policy Comparison

Policy Design	Government Minded to Position	EirGrid Proximity Payments
Transfer Amount (Total)	£2,500 Fixed amount for all distances and voltages.	Ranging from £1,750 to £26,000.[29] Sliding scale considering both proximity to and voltage of qualifying works.
Payment Structure	Funds delivered over 10-year period, as 20 instalments of £125 every 6 months.	Staggered direct payments, with a proportion paid once route is confirmed and construction begins, and the remainder paid upon completion of works.
Eligibility: Infrastructure	New infrastructure and significantly upgraded existing infrastructure. No rural/urban distinction.	New infrastructure (greenfield development) in rural areas only.
Eligibility: Distance	Up to 500m	Up to 200m

[27] See section 13 'Risk and assumptions' for further details.

[28] EirGrid (2018): Community Fund and Proximity Payments Brochure

[29] Maximum payment: €30,000, based on a residential property 50m from the centre line of a new 400kv line. Minimum payment, €2,000 for a residential property within 200m of a new 110kv line. Converted to GBP at an exchange rate of 0.87 and rounded to the nearest £500 for ease of comparison.

Eligibility: Tenure	All residential households	Homeowner occupiers only
Delivery	Centrally administered & legal obligation. Auto-enrolment for vast majority of eligible recipients.	Delivered by TSO directly, ex-gratia payments. Opt-in process for eligible recipients.

20. Elements of the EirGrid scheme could be interpreted as a more targeted form of intervention, with a lower requirement for central government intervention. However, this option has been discontinued and is not subject to formal cost-benefit analysis in the short-list appraisal on the grounds of viability. Previous government consultations on transmission network community benefits indicated a lack of support for the proposals among key stakeholders which would undermine the potential ability for a decentralised scheme to function.[30] This decision was also supported by survey evidence from DESNZ commissioned social research, which indicated a preference amongst respondents for a centrally mandated scheme as well as previous ministerial steers for a preference for a centrally administered scheme.

4. Summary and preferred option with description of implementation plan

21. The government's preferred option, as set out in March 2025 policy paper[31] constitutes a dual approach of the long-list options:
    - Option (B): Counterfactual - voluntary community funds and,
    - Option (C): Mandatory bill discount scheme.

22. Option (B) has already been implemented, through the publication of guidance in March 2025, and it is anticipated that initial funding will be allocated from April 2026 at the earliest. Licenced Transmission Owners (TOs) will play a role in delivering the scheme; therefore, this option is dependent on their cooperation and capacity to deliver.

23. Implementation of Option (C) is dependent on new secondary legislation. Primary legislative powers have been secured via the Planning and Infrastructure Act, which received royal assent in 2025. Secondary legislation is due to be introduced later in 2026. The scheme relies on the scheme administrator being ready to deliver, by completing necessary set up activity ahead of scheme launch in October 2026. Licenced electricity suppliers, and Transmission Owners (TOs) will play a role in delivering the scheme, therefore the option is dependent on their cooperation and capacity to deliver. Amendments to licenced electricity supplier and TO obligations are expected to be set out in secondary legislation to enable this.

24. For the purposes of shortlist appraisal, we will consider the relative costs and benefits of the proposed bill discount scheme relative to the "do-minimum" intervention – the voluntary provision of community funds as our formal counterfactual scenario.

[30] DESNZ (2025): Community benefits for electricity transmission network infrastructure

[31] DESNZ (2025): Electricity transmission infrastructure: proposed bill discount scheme

25. The Impact Assessment accompanying primary legislation considered the potential range in costs and benefits associated with altering the payment level and distance thresholds for identifying eligible properties, which informed the publication of the government preferred position of £2,500 over 10 years for residential properties within 500m of qualifying works.[32] Therefore, these attributes (distance thresholds and payment levels) are not tested further in this assessment, as they are considered settled policy positions. We have however, in this assessment explored the potential costs associated with varying the scheme eligibility criteria for qualifying works, reflecting the decisions taken on the relative trade-offs associated with practical implementation challenges for each option. Refer to the published government response on the consultation on scheme design for further details on the rationale for the decisions made.[33]

26. See details set out in Table 4.1 for the different qualifying works scenarios considered. To avoid confusion with the long-list appraisal, options considered in short-list appraisal have been relabelled as Options 0 – 3.

Table 4.1 Shortlist Appraisal Options

Policy Option	Description
Option 0: Counterfactual/Do Minimum	Voluntary Community Funds for eligible transmission works, calculated as a set rate: £200k per km of eligible overhead line works, £530k per eligible station.
Option 1: Less Ambitious Intervention	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for residential properties within 500m of eligible works. **Qualifying Transmission Works:** Defined subset of eligible wider works
Option 2: Preferred Option	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for residential properties within 500m of eligible works. **Qualifying Transmission Works:** Eligible wider works and enabling works, **excluding** assets developed under a user self-build agreement
Option 3: More Ambitious Intervention	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for

[32] Planning and Infrastructure Act Impact Assessment – Annex 6: Electricity Bill Discount Scheme.

[33] DESNZ (2025): Consultation on scheme design for bill discounts for transmission network infrastructure. Government response to Question 1: Eligible Infrastructure.

	residential properties within 500m of eligible works. **Qualifying Transmission Works:** Eligible wider works and enabling works, **including** assets developed under a user self-build agreement

27. Option 2 has been selected as the preferred way forward following extensive quantitative and qualitative assessment against the critical success factors outlined in 3.2 above; Strategic fit, affordability and Value-for Money, achievability and risk profile, perceived fairness.

28. In recognition of the proposed bill discount scheme being novel and complex given the requirement for geospatial data, government has decided to limit the eligibility criteria for qualifying works to projects where there is sufficient certainty in the processes for data acquisition and verification of qualifying works from the relevant licenced TO, at or before the point of construction. This means the scheme's scope will at launch be limited to wider works and enabling works where consenting and construction is overseen by the licenced onshore transmission owner. This approach will capture the vast majority of residential properties assessed as eligible in the appraisal set out in this Impact Assessment and ensures that bill discounts can be delivered as soon as possible for the majority of projects being delivered for 2030.

29. However, it is acknowledged that some communities also host transmission network infrastructure which is developed by third parties and therefore not built by the licenced onshore TOs and that these communities and households should also be recognised for their role. Communities hosting these projects will continue to benefit from the voluntary community funds guidance. With respect to bill discounts, the government intends to explore ways to expand the scheme to include these types of transmission network infrastructure wherever possible and will keep investigating viable routes to secure the data needed to include user self-build transmission projects in the future.

5. NPSV: monetised and non-monetised costs and benefits of each shortlist option (including administrative burden)

5.1. Methodology for quantified impacts

30. The majority of the quantified impacts in all shortlisted options constitutes a transfer from all electricity consumers to the communities hosting transmission infrastructure projects, either in aggregate (Option 0) or directly to individual households (Options 1-3). These transfers represent no overall change to social welfare. The calculation of these transfer values is heavily dependent on input data detailing the nature of eligible transmission works, which is outlined in more detail below.

Identifying Eligible Transmission Works

31. For the purposes of this analysis, we have grouped eligible transmission works into two main categories. These are:
    (1) **Wider Works - Strategic Network Investment:** Refers to national scale investments which aim to upgrade and future proof the network to future energy demands and decarbonisation goals. Works in this category are identified through NESO-led strategic network planning such as the Network Options Assessment (NOA) and Ofgem funding mechanisms, such as the Accelerated Strategic Transmission Investment (ASTI) framework and Large Onshore Transmission Investment (LOTI) re-openers.

    (2) Enabling Works: Refers to transmission assets required to facilitate specific customer connections, rather than to address system-wide needs. They arise from individual connection applications (generation, demand) and are scoped to ensure the connection can be made safely and securely on an ongoing basis. In practice, enabling works span a wide range from small scale local works (short underground cable sections and minor substation extensions) to very large projects (such as new high-voltage substations).

32. The responsibility for construction of enabling works is determined as part of contractual agreement between the connecting customer and host transmission owner. For the purposes of policy appraisal, it is assumed that all qualifying overhead line circuits are developed by the licenced Transmission Owner and that any qualifying stations within the boundaries of planned/consented generation sites would be developed under a User-Self Build agreement. The NESO publishes registers of all live transmission connection agreements and associated enabling works.[34,35]

[34] NESO Transmission Entry Capacity (TEC) register

[35] NESO Transmission Works Report (TWR)

33. As set out in the government response to the public consultation on scheme design for the proposed bill discount scheme, eligible qualifying works will be limited to wider and enabling works where construction is overseen by the licenced transmission owner – i.e., excluding any transmission assets developed by third parties under a user-self build agreement.[36]

34. Data on strategic network investments is provided to DESNZ by licenced Transmission Owners in quarterly data returns which document the progress of projects, identified as essential for Clean Power 2030 in NESO's Clean Power Advice.[37] For each project, this data return also provides information to support the identification of infrastructure that could be in scope of the delivery of community benefits. This is in the form of the distance of new or significantly upgraded overhead line in kilometres and the number of new or significantly extended substations.

35. Due to known interactions with the ongoing TM04+ grid connection reforms it has not been deemed proportionate to carry out an exhaustive assessment of all potentially eligible enabling works within the appraisal period considered for this intervention, as the scope and scale of enabling works required is likely to be materially different upon the conclusion of grid connection reforms.[38]

36. Therefore, the initial strategic network investment pipeline has been supplemented by a proportionate and non-exhaustive analysis of potential enabling works required to facilitate the increased number of connections of renewable generation assets to the transmission network. This has been based on a data matching exercise linking known projects in the planning pipeline covering; onshore wind, solar and battery energy storage, and was carried out on data provided by an external energy consultancy collated for a separate analytical purpose.[39]

37. This initial connection pipeline was supplemented by additional data on potential works associated with the onshore components of the offshore transmission network, set out in strategic planning documents and verified with internal sector leads.[40] This combined dataset of potential works was matched to entries in the Department's Renewable Energy Planning Database (REPD) and NESO's Transmission Entry Capacity (TEC) register and details of works required outlined in both the Transmission Works Report (TWR) and Transmission Owner Reinforcement Instruction (TORI) quarterly update reports. [41,42,43]

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[36] DESNZ (2025): Scheme design for bill discounts for new transmission network infrastructure. Government response to question 1 eligible infrastructure.

[37] Network Options Assessment (NOA) coded transmission projects outlined in NESO Clean Power 2030 – Annex 2: Networks, connections and network access analysis.

[38] See Ofgem (2025) TM04+ Impact Assessment, sections 5.9 – 5.17 for further details.

[39] Data provided upon request by Regen for transmission connected generation and storage assets included in: Connections reform – Clean Power 2030 strategic alignment.

[40] NESO (2022): A Holistic Network Design (HND) for Offshore Wind

[41] DESNZ (2025): Renewable Energy Planning Database: Q2 2025

[42] NESO Transmission Entry Capacity (TEC) register; NESO Transmission Works Report

[43] Scottish Power Energy Network - Q3 2025 TORI Quarterly Report; Scottish & Southern Electricity Networks TORI Quarterly Update Reports

38. Once a pipeline of potential projects had been established filtering took place to exclude projects which had either:
    (i) Not met the defined eligibility criteria as either new or significantly upgraded infrastructure
    (ii) Started construction before the policy start date,[44]
    (iii) Constituted a co-located asset.[45]

39. The filtered list was then subjected to manual searches of publicly available information in public consultation documents and Environmental Impact Assessments for relevant planning applications, accessed via the Planning Inspectorate for England and Wales and the Scottish government's Energy Consents Unit. Manual searches enabled the identification to a high degree of certainty of the likely location of substation works associated with connection projects – as well as identifying any associated section 37 works which would be required by the host transmission operator, where appropriate.[46]

Table 5.1 Project Pipeline: Eligible Overhead Line (OHL) & Substation Works – Descriptive Statistics

Infrastructure Project Type	Works Type	Frequency
Strategic Wider Works	Overhead Line (km)	1,782 km
	Stations (count)	58
Enabling Works: Transmission Owner Development	Overhead Line (km)	634 km
	Stations (count)	11
Enabling Works: User Self Built Assets	Overhead Line (km)	N/A
	Stations (count)	167
Total	**All**	**Overhead line: 2,416km** **Stations: 236**

40. It is worth noting, the project pipeline outlined in Table 5.1 above should not be considered an exhaustive assessment of the potential works associated with transmission network customer connections. For instance, it does not account for any low-carbon dispatchable power, alternative energy storage assets (i.e., pumped hydro) or any demand connections (i.e., data centres). However, given the interaction with the ongoing grid connection reform process, and quantity of total potential connection projects in the pipeline, a proportionate approach has been taken. The total count of connection projects included in our appraisal is 162, filtered

[44] The policy eligibility date is for main (civil) construction works to have commenced after the 10th March 2025, the date when the policy intention was formally announced by government.
[45] To avoid double counting in the scenario where battery storage located alongside new generation capacity – for which the transmission connection works would be joint.
[46] All of the 634km of eligible OHL enabling works are linked to onshore wind projects in Scotland.

down from an original list of 517 unique projects across the initial range of technologies considered. In the October 2025 NESO Transmission Entry Capacity register, this unfiltered list accounted for roughly 33% of the approximately 1,500 direct connections listed which are not either already built or under construction.[47]

41. The underlying pipeline data for quantification in both the counterfactual and policy option scenarios is fundamentally the same as for the counterfactual, with the differences for final quantification of impacts outlined in more detail in the remainder of this section.

Policy Options:

Counterfactual: Option 0 (Do-Minimum) – Voluntary Community Funds

42. The pipeline data outlined above is multiplied by the rates set out in published guidance:
    - £200,000 per km of eligible overhead line works
    - £530,000 per fixed substation/switching station

43. These aggregate transfer values are then profiled based on expected construction start dates, and an assumption for the length of time communities may spread the funding over.[48] For strategic network investment projects, forecast construction start dates are provided by TOs. For customer connection projects these start dates are calculated by applying an assumed total construction period for renewable generation technologies to the public connection agreement data as listed in the TEC.[49]

Policy Options (1-3): Mandatory Bill Discount Scheme (BDS)

44. All beneficiary households receive the same nominal value of payment through the BDS and so the aggregate transfer value of the scheme is driven by the number of beneficiary properties and the time profile of discount delivery. Determining the number of beneficiary properties for each eligible infrastructure project is therefore a particularly sensitive element of the analysis.

Identifying Eligible Households for the BDS

45. In the analysis produced to accompany the primary legislation Impact Assessment[50] the calculated number of beneficiary properties was derived from property density estimates in a 1998 study on the number of residential properties living within various

[47] NESO – Transmission Entry Capacity (TEC) register 14th October 2025. Due to ongoing grid connection reform, it has not been deemed proportionate to assess the potential eligibility of every existing entry in the TEC. The nature of enabling works is not uniform across technology types so it has not been deemed appropriate to apply a scale approximation for connection agreements which have not been considered in this appraisal.

[48] Up to a maximum of 15-years in the guidance. Central estimate is 5-years reflecting evidence from stakeholders regarding likely community preferences.

[49] DESNZ (2023): Electricity generation costs 2023 - Annex A: Additional estimates and key assumptions

[50] Planning & Infrastructure Bill Impact Assessment: Annex 6 – Electricity Bill discount scheme

distances of the existing network in England and Wales.[51] This property density per km of overhead line (OHL) estimate was then applied to the reported length of OHL for proposed strategic network projects, collected by the department. However, property density estimates per km of OHL based on the transmission network in England and Wales are likely to be an overestimate compared to new network. England and Wales have a higher population density (409 people per sq km) than Scotland (71 people per sq km).[52] Additionally, the existing electricity transmission network was built to facilitate the transmission of electricity generated by fossil fuel powered generation stations. These generation plants were often centred in industrialised regions, situated close to demand centres. New transmission connected generation is more typically sited in rural areas or offshore, further from the site of demand and so new network infrastructure is more likely to run through areas with a lower population density.

46. The approach used to estimate the number of eligible properties has since been updated, with two approaches taken to quantify the number of eligible households, reflecting the availability of geospatial data associated with eligible projects.

47. **(1) Bottom – up: geospatial identification of eligible households:**

48. The point locations of all properties in Great Britain have been checked against a theoretical eligibility zone, defined geospatially as the dilation of 500m around the infrastructure geometry, for each in scope work. Properties which were flagged as having their point location inside the eligibility zone were then filtered by classification to obtain a count per project for residential properties only. These point locations and property classifications were accessed via Ordnance Survey data.[53] Each property is assigned a unique property reference number (UPRN) which can be matched to other property data sets.

49. This process has been run against the following input data:
    i. Where possible, network infrastructure geometries were obtained directly as shapefiles from Transmission Owners or through open access planning data.[54] These shapefiles provide a high degree of confidence in the location, and geographical features of network projects. However, this 1st best approach to

[51] SAGE (2007): Stakeholder Advisory Group on ELF EMFs (SAGE) Precautionary approaches to ELF EMFs page 61

[52]ONS (2025): Estimates of the population for the UK, England, Wales, Scotland, and Northern Ireland MYE5: Population density for local authorities in the UK, mid-2011 to mid-2024

[53] The data matching process outlined is based on an internal geospatial model developed in Python. OS AdressBase data is covered by the Public Sector Geospatial Agreement (PSGA). It includes locations for around 33 million addresses, as well as additional metadata and is updated frequently.

[54] Planning and housing data in England

data collection only accounts for a small proportion (17%) of total eligible overhead line works in the project pipeline used in this appraisal.[55]

ii. In the absence of 1st best data described above, shapefiles for indicative routes were provided by NESO.[56] These indicative routes vary in accuracy and provide a lower degree of confidence. This 2nd best data accounts for 34% of total eligible overhead lines works in the pipeline used in this appraisal.

iii. For eligible substation works, point locations were obtained through manual searches of public consultation documents and Environmental Impact Assessments. For these works, a uniform assumption of approximately 32,000m^2 footprint for a substation is applied and the eligibility zone has been calculated as a 500m dilation around the theoretical substation boundary. This approach has been applied for all (100%) of eligible substation works included in this appraisal.

50. **(2) Top – down: applying an assumed residential property density ratio to proposed network infrastructure lengths:**

51. For the remaining 49% of eligible overhead line works, not covered by the analytical approach outlined above, an updated residential property per kilometre of overhead line has been calculated to replace the previous 1998 estimate based on the existing network in England and Wales. This has been derived by calculating the total number of point locations for all properties in Great Britain against a theoretical eligibility zone calculated from publicly available shapefiles off the existing transmission network in each Transmission Owner license area.[57] After filtering for residential properties and dividing the total number of properties by the total amount of overhead line in each licence area it is possible to derive the values outlined in Table 5.2. The values should be interpreted as the number of residential properties within set distances of the existing transmission network, where the disparity in population density between the Scottish licence areas (SPT & SHET) and England & Wales (NGET) is apparent.

[55] Proportion of eligible works identified by each modelling approach are in reference to assessment of Option 3, the most expansive eligibility criteria considered.

[56] NESO: Beyond 2030 Interactive Web Map

[57] National Grid Electricity Transmission and Scottish Hydro – Electric Transmission existing transmission network route shapefiles obtained via Transmission network data portals. Scottish Power Transmission shapefiles were obtained through a data request. Network route maps | National Grid, SSEN Transmission Overhead Line Supergrid — SSEN Transmission.

Table 5.2: Residential property density per kilometre within defined distances of the existing GB transmission network, by licence area.

Transmission Owner Licence Area[58]	Number of residential properties per km within eligibility distance: 550m
National Grid Electricity Transmission (NGET)	106
Scottish Power Transmission (SPT)	42
Scottish Hydro Electric Transmission (SHET)	12

52. The theoretical eligibility distances displayed in Table 5.2 are the proposed eligibility distance threshold of 500m, plus an additional 50m buffer to account for the proposed methodology for calculating eligible households. The eligibility radius would not be able to be accurately calculated from the centre line of eligible infrastructure from construction commencement; therefore, it is assumed that the Limit of Deviation (LoD) specified in planning applications will be used as the basis for estimating the eligibility zone. The LoD provides a corridor within which TOs can "micro-site" pylons during construction to account for unforeseen issues (i.e., ground stability challenges with the proposed tower locations). There is no fixed limit for a LoD width, but from engagement with TOs and a review of recent s37 applications for similar works these are typically in the region of 100m in width (50m either side of the preferred route).[59]

53. Applying the methodologies outlined above to the project pipeline data collated for this analysis provides the following total number of eligible properties at the two eligibility zones tested in this appraisal. The range in estimates reflects both the range in approaches applied for strategic network investment works as well as a +/- 20% sensitivity adjustment reflecting residual uncertainty in the approach taken for customer connections.

Table 5.3: Estimated number of eligible properties – by eligible works type

Infrastructure Project Type	Works Type	Station Count	Total Length (km)	Estimated number of eligible residential properties[60]
Strategic Wider Works	Overhead Line	N/A	1,782	101,000 – 130,000
	Stations	58	N/A	4,000 – 7,000

[58] The transmission network in England and Wales is owned and operated by National Grid Electricity Transmission (NGET), while Scotland is broken into 2 Transmission Owner license areas. Scottish Power Transmission (SPT) provide transmission to Southern Scotland while Scottish Hydro – Electric Transmission (SHET) - also known as Scottish and Southern Electricity Networks (SSEN) – operate in Northern Scotland.

[59] The alternative option of calculating eligibility once construction works had been completed was ruled out following ministerial engagement.

[60] Estimated number of eligible residential properties rounded to the nearest 1,000 therefore, totals may not sum due to rounding.

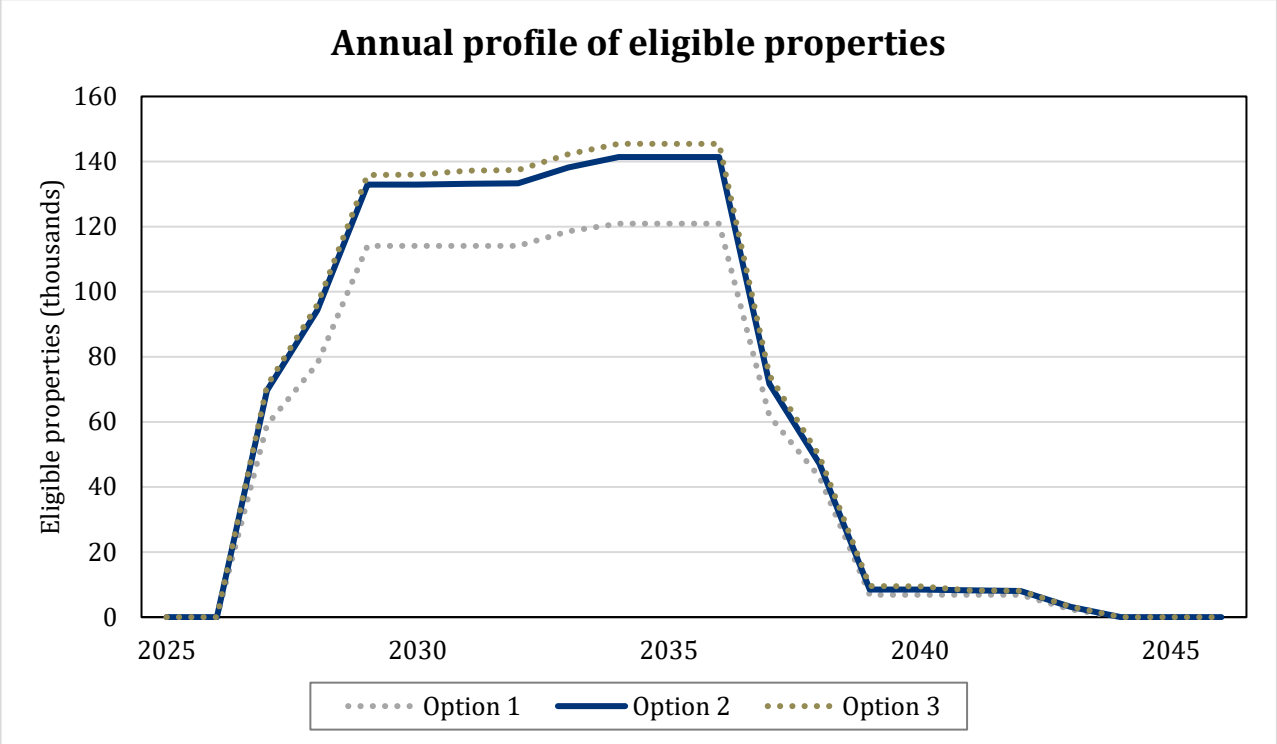
Enabling Works: Transmission Owner development	Overhead Line	N/A	634	16,000 – 24,000
	Stations	11	N/A	<1,000
Enabling Works: User Self Built Assets	Overhead Line	N/A	0	0
	Stations	167	N/A	3,000 – 5,000
Total	**All**	**236**	**2,416**	**125,000 – 166,000**

54. Applying these estimates to the eligibility criteria for each policy option outlined in Table 4.X above, results in the estimated number of eligible residential properties, per shortlist option as summarised in Table 5.4 and Figure 5.1 below.

Table 5.4: Estimated number of eligible properties – by policy option

Policy Option	Description	Estimated number of eligible households
Option 0: Counterfactual/Do Minimum	Voluntary Community Funds for eligible transmission works, calculated as a set rate: £200k per km of eligible overhead line works, £530k per eligible station.	N/A – funds distributed to voluntary and community organisations not individuals or households.
Option 1: Less Ambitious Intervention	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for residential properties within 500m of eligible works. **Qualifying Transmission Works:** Defined subset of eligible wider works	**106,000 – 136,000**
Option 2: Preferred Option	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for residential properties within 500m of eligible works. **Qualifying Transmission Works:** Eligible wider works and enabling works, **excluding** assets developed under a user self-build agreement	**122,000 – 161,000**
Option 3: More Ambitious Intervention	**Scheme Design:** Mandatory bill discount scheme: £2,500 over 10 years for residential properties within 500m of eligible works. **Qualifying Transmission Works:** Eligible wider works and enabling works, **including** assets developed under a user self-build agreement	**125,000 – 166,000**

Figure 5.1: Mandatory Bill Discount Scheme - Annual Profile of Eligible Properties



55. The appraisal period applied in this analysis covers the period 2025 – 2044, as 2044 is the point at which the final transfer payment is expected to be made, based on the information we have available at this time - i.e., the last project we currently have sufficient information on to include in this analysis is expected to commence construction in 2035.[61] The choice of this appraisal period reflects the projects which we have been able to collect sufficient information on to include in cost modelling and is not reflective of a definitive end point to the scheme. As currently designed, there could be further cost implications beyond the appraisal window used in this analysis but we have not been able to quantify and it has not been deemed proportionate to extrapolate, given the uncertainty in the project pipeline. As a result, it is likely that later years in our appraisal period underestimate the potential costs implications, as discussed in further detail in Section 13. Risks and assumptions.

56. As set out in the government response, transmission network infrastructure projects that start main construction works before March 2025 and after the end of 2040 will not be in scope of the scheme, regardless of whether they otherwise meet the eligibility criteria. The government intends to review this scheme end date between 2035-2040 to mitigate risk of excluding key infrastructure projects that are delayed.

57. All values presented in this Impact Assessment are 2025 price base year. Unless stated otherwise, aggregate costs are discounted to 2026 present value year in line with HMT Green Book guidance and consumer bill impacts are undiscounted.

[61] While there are transmission connection agreements dated out to 2039 included in NESO's Transmission Entry Capacity (TEC) register, for the purposes of this policy appraisal we have truncated the assessment of enabling works to 2035 given the underlying uncertainty in assumed lower maturity projects and due to the interaction with TM04+ grid connection reforms.

5.2. Transfers

58. Applying the methodology outlined above – the following aggregate transfer values have been derived for each of the shortlisted policy options. Totals for Options 1-3 are inclusive of the costs of Option 0 which will be delivered alongside the proposed bill discount scheme as a dual approach to delivery community benefits.

Table 5.5 Total Transfer Values

Policy Option	Low Estimate	Central Estimate	High Estimate
Option 0: Do Minimum/Counterfactual: Voluntary Community Funds Guidance	£545m	£600m	£650m
Option 1: Lower Ambition Intervention	£770m	£860m	£945m
Option 2: **Government Preferred Position**	£805m	£900m	£995m
Option 3: Higher Ambition Intervention	£815m	£910m	£1005m

5.3. Costs

59. There will be costs associated with delivering each of the policy options considered, these are considered in turn as, costs to industry and costs to government in the following sections. The direct costs will be incurred by either licenced Transmission Operators (TOs) or electricity suppliers; however, it is anticipated that the vast majority if not all costs will be passed on to electricity consumers as indirect costs. For simplicity, the direct costs are described here, with pass through considerations outlined in further detail in subsequent sections.

5.3.1. Industry Administration Costs

Counterfactual: Voluntary Community Funds Guidance

60. **Administration:** The voluntary guidance sets out an expectation that administration costs incurred by Transmission Operators (TOs) associated with delivering community funds should not exceed 10% of the total value associated with their funds. These costs include but are not limited to, capacity building, feasibility work, staff costs, marketing and third-party administration. All costs associated with delivery of community funds will be subject to Ofgem scrutiny, and subject to approval would be permitted to be passed through to all electricity consumers along with the estimated transfer values. For the purposes of this analysis, we apply a simple fixed 10% assumption on the annual transfer profile, to illustrate a maximum expected cost.

61. **Familiarisation**: It is likely that TOs, will have incurred familiarisation costs to read, understand and plan their response to the guidance. The three licenced TOs in GB

have all also been involved with shaping the guidance, which will have come at a cost in terms of time spent engaging DESNZ policy officials on these matters, however, it has not been deemed proportionate to retrospectively quantify.

Policy Options 1 - 3: Proposed Bill Discount Scheme

62. **Administration:** Costs will likely be incurred by licenced electricity suppliers who are active in the domestic market to deliver the transfer payments associated with the policy option. Licensed onshore Transmission Owners (TOs) are also likely to incur costs associated with the sharing of geospatial data associated with eligible projects. However, these costs have not been quantified and are assumed to be relatively minor given the production of detailed geospatial data is already factored into existing routeing and consenting processes.

63. The potential costs incurred by licensed electricity suppliers have been separated into two main components:

64. **Adjustments to internal business practices:** These costs include activities such as carrying out internal training and updates to IT systems to facilitate the delivery of transfer payments and to support verification and auditing processes.

65. **Delivery of transfer payments to customers:** This is the ongoing cost associated with the transfer payment being delivered to eligible customers and have been estimated by disaggregating the annual profile of eligible households into three distinct groups from which it is expected there will be varying unit costs associated with delivery of payments. These groups are outlined in more detail below.

(i) **Auto-enrolment:** The vast majority of households identified are expected to be automatically enrolled into the scheme, once the eligible Unique Property Reference Number (UPRN) is matched to the Meter Point Administration Number (MPAN) and electricity supplier is notified. The participation rate assumption is based on the reported successful delivery rates for the Energy Bill Support Scheme (EBSS) in the department's interim evaluation report and also reflects stakeholder engagement which suggest some residents particularly opposed to transmission infrastructure may opt-out of receiving the payments.[62]

(ii) **Traditional Pre-Payment Meter (PPM):** The majority of customers on pre-payment meters will be treated in the same way as group (1) if they have a smart pre-payment meter. However, official DESNZ statistics show that as of the end of 2024 36% of all PPM customers are still on traditional meters.[63] In this instance, the current preferred delivery route is via vouchers, sent directly to the customer by their supplier. This has a much higher assumed unit cost per customer to deliver and would require an increased frequency of delivery compared to auto-enrolment due to pre-payment meter credit limits. The participation rate assumption is based on the reported

[62] DESNZ (2025): Interim Evaluation of Domestic Energy Affordability Support Schemes in Great Britain
[63] Assumed that 12.6% of all meters are pre-payment meters, of which, 36% operating in traditional mode, source: DESNZ (2025): Smart meters in Great Britain, quarterly update December 2024

redemption rates for the Energy Bill Support Scheme (EBSS) in the department's interim evaluation report.

(iii) **Opt-in/non-traditional relationship with supplier:** Not all residential households have a typical relationship with an electricity supplier. This can be for numerous reasons, such as; energy consumers living off the gird, residents of a multi-occupancy building (i.e., care homes), or private tenants supplied via a landlord with a commercial meter. The aggregate population falling into this category in GB has been estimated before in the Energy Bill Support Scheme (EBSS) Impact Assessment.[64]

66. For the purposes of this analysis, we have calculated the proportion of households potentially falling into this category by dividing the total population estimated in the EBSS IA, by the estimated total number of domestic electricity MPANs and assuming the distribution of these types of households are uniform across GB.[65] The participation rate assumption is based on the reported successful application rates for the Energy Bill Support Scheme (EBSS) in the department's interim evaluation report. It is assumed that payment of annual transfer values to opt-in households is an activity that will be the responsibility of the scheme administrator, therefore these households are excluded from the calculation of annual industry administration costs.

Table 5.6: Transfer Administration Costs by eligibility sub-group

	Eligible Population (% of total)	Assumed participation rate (%)	Participation Adjusted Population (% of total)
Auto-enrolment	94%	99%	93.0%
Traditional PPM	4%	88%	3.8%
Opt-in	1%	18%	0.3%

67. One of the primary objectives of the proposed policy is that as many of the households identified as eligible for this scheme, receive the full value promptly and the scheme has been designed to maximise the number of households who can automatically receive a payment. However, some types of households will be required to actively participate in the scheme, and we have therefore adjusted the number of estimated eligible households, using assumptions of each customer group's likelihood of engaging with the scheme to obtain the number of recipient households. These assumptions are informed by DESNZ evaluations of previous similar schemes such as the Energy Bill Support Scheme (EBSS).

68. After allocating the estimated population of eligible households into the user engagement subgroups outlined in Table 5.6 above, the costs for licenced electricity suppliers to fulfil their obligations for the scheme are estimated by quantifying the

[64] BEIS (2022): Energy Bill Support Scheme Impact Assessment - see Table 12.
[65] Assumed 28 million domestic households in Great Britain, source: DESNZ (2024) Subnational electricity and gas consumption summary report.

potential costs associated with defined transitional, and annual scalable and non-scalable administrative activities outlined in Table 5.7 below.

Table 5.7 – Assumed Administrative Activities for Licenced Electricity Suppliers

Cost Type	Cost Activity	Description
Transitional Administrative Activities	Training	Project groups attending training event prior to scheme launch
	Updates to IT Systems	Project team to manage and deliver any required updates to supplier IT systems to deliver the grant automatically
Annual Non-Scalable Administrative Activities	Reporting & verification of customer numbers and delivery	Engaging with scheme administrator on MPANs supplied in scope of payments per discount delivery period. Verifying if MPANs are still actively supplied (i.e., switched supplier or de-energised meter etc.), oversight from managers, sign off from senior officials and providing confirmation to scheme administrator.
	Processing payments	Internal finance team to prepare funding from the customer numbers as verified/prepared.
	Communication to customers	Preparing email and mail communications about the scheme and delivery for customers, it is assumed employees are aware of the scheme following familiarisation and training. Assumed at a minimum each eligible customer is contacted at least twice (i.e., notification of eligibility status when they receive first payment and last payment). This cost reflects the time taken to prepare template and verification of list of customers who would require contacting (if any) during each delivery period. Cost of postage included in scalable cost activities below.
	Participating in reconciliation process	Internal finance team prepare statement of net position for each reporting period and clarify if any funds need to be requested or provided as part of the reconciliation process, approved by managers and senior officials.
	Audit & verification	Assumes all suppliers are subject to audit and verification activities over the delivery period. This required finance and senior official's time. Assume a senior board of 6 members approve the audit preparation.
Annual Scalable Administrative Activities	Communication to eligible customers	Email and/or posting communication to recipients. It is expected that all eligible recipients will receive at least two letters/emails (notification of eligibility status ahead of first payment and last payment). This activity captures the relative cost of printing and postage which scales in line with number of eligible customers served. Assumed unit cost of ~£1.00 covering both printing and postage.

Annual Scalable–Transfer Delivery Costs	Processing of payments to eligible customers (Auto-enrolled)	Assumed unit cost of £0.04 per payment processed for direct debit, credit and smart pre-payment meter customers.
	Billing updates	Assumed unit cost of ~£0.60 per billing update to reflect additional £250/yr credit on accounts.
	Manual Processing	Assume a small number of auto payment cases (5%) would require manual processing due to errors. Additional unit cost of ~£0.20 assumed per case.
	Voucher Delivery to Traditional Pre-payment meter (PPM) customers	Assumed unit cost of ~£1.50 per voucher delivery for traditional PPM customers.

69. The assumed resource requirement in each activity outlined above, in terms of both Full Time Equivalent (FTE) staff and hours for transitional and non-scalable activities and unit costs per annual scalable activities have been proxied using previous assessments of similar policies, such as the Energy Bil Support Scheme and have been tested with industry stakeholders.[66] The staff and hour assumptions are converted into equivalent costs using relevant hourly wage estimates from the ONS Annual Survey of Hours and Employment (ASHE).[67]

70. Applying the annual profile of estimated households per policy option considered to the administrative cost assumptions outlined above yields the total estimated supplier administrative burden across the full appraisal period (2025 – 2044) as summarised in Table 5.8 below.

71. Due to the obligations placed on suppliers in delivering the scheme, the government believes it is reasonable that suppliers should be allowed to recover administration costs incurred. The government also has this view because suppliers will likely have differing numbers of customers who are eligible for the scheme and therefore want to ensure those with more eligible customers are not unfairly impacted. However, government is also keen to manage the potential impact of the scheme on billpayers and believe that it is appropriate that a maximum limit should be set for

[66] See DESNZ (2022): Energy Bill Support Scheme – Impact Assessment, Annex A: Tables 9 & 10. Where relevant unit costs assumptions have been rebased to 2025 prices. Assumptions shared in February 2026 with participants of the department's supplier delivery group which meets regularly to discuss implementation of the proposed bill discount scheme.

[67] ONS (2023): Annual survey for Hours and Earning (ASHE) Table 29.5a

what administrative costs a supplier can recover. The exact details of this limit are still under consideration.[68]

Table 5.8: Bill Discount Scheme - Industry Administration Costs by policy option

Policy Option	Total Cost
Option 1: Less Ambitious Intervention	£3.1m - £3.5m
Option 2: Preferred Option	**£3.3m - £3.8m**
Option 3: More Ambitious Intervention	£3.4m - £3.9m

72. **Familiarisation:** In each of the policy options considered, there will be costs incurred by licenced electricity suppliers active in the domestic market to read and understand the requirements, brief senior staff, create and disseminate guidance to facilitate their response to the new obligation. Our cost estimate for these familiarisation costs assumes that this would be equivalent to 1 full-time equivalent per electricity supplier requiring 4.5 months.[69] This is a one-off cost, which does not vary based on the level of transfer payment (i.e., across options 1 – 3) or size of supplier and is assumed to occur in 2026.

73. The aggregate administrative costs incurred by businesses (both licenced TOs and electricity suppliers) for the policy options considered within this appraisal is summarised in Table 5.9 below. The vast majority of the costs are accounted for by the counterfactual scenario.

Table 5.9 - Total Industry Administration Costs (Full Appraisal Period: 2025-2044)

	Option 0: Counterfactual – Voluntary Community Funds	Options 1 – 3: Proposed Bill Discount Scheme
Familiarisation	Not Quantified	~£1m
Administration	£55m – £65m	£58m - £69m
Total	£55m – £65m	£58m - £70m

5.3.2. Government Administration Costs

Counterfactual: Voluntary Community Funds

74. There will have likely been costs incurred by government associated with the implementation of the voluntary guidance, covering the resource allocation to developing the policy position, consulting, drafting the guidance and stakeholder engagement. This is likely to be spread across both DESNZ and Ofgem. However,

[68] DESNZ (2025): Consultation on scheme design for bill discounts for transmission network infrastructure. See government response to question 17 for further details.
[69] BEIS (2022): Energy Bill Support Scheme Impact Assessment - Table 9

there is likely to be limited ongoing administration costs now that the guidance has been published and it has not been deemed proportionate to retrospectively quantify.

Policy Options: Proposed Bill Discount Scheme

75. There will be costs incurred by government associated with the implementation and ongoing administration of the proposed bill discount scheme. Potential costs incurred by government can be broadly split into the following two categories:

    (i) **Set up/Implementation Costs**: These cover the RDEL and CDEL allocations across the period 2025 – 2026, to develop the scheme and establishing a formal monitoring and evaluation programme.

    (ii) **Business as Usual (BAU) delivery costs:** These are based on the preferred scheme administrator's initial assessment of the potential ongoing costs to facilitate the scheme. It is important to note that initial cost estimates provided are uncertain, and subject to further development. For instance, operational costs are likely to be contingent on digital discovery works which are ongoing. Reflecting this uncertainty a +/- 20% sensitivity adjustment has been applied. All scheme administrator delivery costs are based on the proposed scheme as outlined in Option 2 and are assumed to be broadly equivalent in all proposed bill discount scheme options assessed.

76. Certain defined costs incurred by the scheme administrator in the delivery phase of scheme would be recouped via the levy on consumer bills, whereas all other costs to government associated with implementation would be covered by existing departmental budgets, as is set out in Table 5.10 below.

Table 5.10: Total Estimated Cost to Government (Proposed Bill Discount Scheme, Full Appraisal Period 2025-2044)

	Options 1 – 3: Proposed Bill Discount Scheme
Total	£22m - £33m
Of which: cost to government	£11m - £16m
Of which: cost to electricity consumers (recouped via levy)	£11m - £17m

77. The estimated government administration costs outlined in Table 5.10 above do not account for any potential variance in the administrative burden associated with verification of eligible qualifying works and acquisition of geospatial data from relevant parties under each of the policy options appraised for the proposed bill discount scheme. Although not explicitly quantified it is anticipated that increasing the scope of qualifying works to include assets developed by third parties under a User-Self Build agreement (Option 3) would result in a material increase in the administrative burden incurred by the scheme administrator, which would have knock on implications for consumers funding the scheme. A qualitative assessment of the

potential administrative burden under each scenario has informed the short-list appraisal and selection of a preferred option, as outlined in Section 4.

5.4. Non-Quantified & Non-Monetised Impacts

78. Investment in local community and voluntary organisations in areas of GB hosting transmission network infrastructure (Option 0 – voluntary community funds) may yield significant, local and regional socio-economic benefits depending on the context within which funds are spent. Licenced TOs have previous experience of delivering community grant schemes and/or investments in Consumer Value Propositions (CVPs) within their licence areas. National Grid Electricity Transmission (NGET) have distributed more than £2.5m in grants since 2021 to support local community projects, delivering a wide range of environmental, social and economic benefits.[70] Likewise, Scottish Power Electricity Networks (SPEN) have overseen £25m in community investment via their Green Economy Fund in T1 (2018 – 2021) and Net Zero Fund in T2 (2022 – 2025), and have estimated to have achieved a social return on investment (SROI) from the T2 Net Zero Fund of approximately £3.10 per £1 spent.[71] Therefore, there is reason to believe similar community investment programmes overseen by TOs in collaboration with host communities could continue to yield significant economic, social and environmental benefits. As the guidance published by government is not prescriptive in defining what the funds should be spent on, it has not been deemed proportionate to attempt to quantify the potential spill-over benefits associated with this investment for the local/regional economies impacted.

79. As outlined in the rationale for intervention, all policy interventions assessed above aim to recognise the role of communities in hosting transmission infrastructure. It is anticipated that provision of a defined benefit, either collectively to the community (Option 0) or in the form of direct transfers to individual households (Options 1-3) may improve community engagement with developers in the various stages of development and therefore contribute to the wider programme level objective of supporting an accelerated deployment of critical transmission network infrastructure. There are potentially significant indirect benefits associated with the scenario where these policy interventions are successful in supporting these objectives, with accelerated deployment and the avoidance of delays to planned network build likely to yield significant reductions in network constraint costs, and therefore end consumer bills, relative to the scenario where delays persist.

80. The National Energy System Operator (NESO) typically manages constraints by paying generators to switch off in locations where the network is congested and paying generators to switch on in locations closer to electricity users. Analysis by NESO suggests that network constraint costs could rise from current levels of around £1.7bn in 2024 to a peak of around £8bn in 2030.[72] However, if critical transmission

[70] National Grid Electricity Transmission (NGET) RIIO-T3 Business Plan, December 2024 p.69

[71] SP Energy Networks RIIO-T3 Business Plan, Environmental Action Plan, December 2024, p.95

[72] Calculated using NESO Monthly Balancing Services Summary (MBSS) data and NESO (2024) Advice on achieving clean power by 2030.

network projects are brought forward and delays to plans for wider network expansion are avoided, this peak in costs could be reduced, delivering savings of approximately £4bn in 2030.[73] This is estimated to be equivalent to an average saving of approximately £55 for an average dual-fuel domestic consumer in 2030, compared to the scenario where delays persist.[74]

81. Given the uncertainty in the causal chain and potential interactions with other factors which can influence the likelihood of this objective being achieved, it has not been deemed appropriate to quantify the extent to which the policies considered in this business case may contribute to any potential reduction in constraint costs.[75] Implementation of these policies may support the likelihood of this wider programme objective being achieved, but themselves alone are not sufficient to deliver this. If this acceleration scenario is achieved, the balancing cost savings in 2030/31 estimated by NESO and Ofgem, would likely more than offset the estimated cost of the preferred policy option, while noting that any potential cost savings associated with this scenario should be considered in the round with the costs required to fund the investment in new infrastructure, which are not in scope of this appraisal.[76]

5.5. Net Present Social Value

82. The aggregate cost-benefit analysis figures for shortlisted policy options are summarised in Table 5.9 below. As there are no quantified benefits associated with the policy, the Net Present Social Value (NPSV) of all options assessed is negative, reflecting the costs both to government and industry to administer the transfer payments. Transfer payments are excluded from the calculation of NPSV as they are a benefit to the recipient and are a cost to the funder and therefore do not make society as a whole better or worse off. Therefore, Net Present Social Value is in this instance, not a particularly useful analytical lens for informing judgements on the preferred level of government intervention. If quantification of non-monetised benefits was possible, it is probable that the NPSV of policy options considered would be positive, due to the significant potential benefits of accelerated deployment of critical transmission infrastructure. However, given the uncertainty in the relationship outlined in 5.4 above, it has not been deemed proportionate to assign likelihood estimates. Further analysis, setting out the potential cost implications for representative domestic and non-domestic electricity consumers to fund the policy options considered is set out in sections 6 – 8.

[73] NESO (2024) Advice on achieving clean power by 2030.
[74] Ofgem (2025) RIIO-3 Final Determinations – Impact Assessment.
[75] Such as potential risk of delays due to; supply chains for materials and skilled labour, system access, and land acquisition. A monitoring and evaluation programme (see section 14), has been designed to attempt to fill some of the evidence gaps in the causal chain.
[76] Ofgem (2025) RIIO-3 Final Determinations – Impact Assessment.

Table 5.11: Cost-Benefit Analysis: Summary[77]

Policy Option	Measure	Low Estimate	Central Estimate	High Estimate
Option 0 Do Minimum/Counterfactual: Voluntary Community Funds Guidance	Net Present Social Value	-£55m	-£60m	-£65m
	Total Transfers	£545m	£600m	£650m
	Total Costs	£55m	£60m	£65m
Option 1: Less Ambitious Intervention	Net Present Social Value	-£80m	-£90m	-£105m
	Total Transfers	£770m	£860m	£945m
	Total Costs	£80m	£90m	£105m
Government Preferred Position Option 2	Net Present Social Value	-£80m	-£90m	-£105m
	Total Transfers	£805m	£900m	£995m
	Total Costs	£80m	£90m	£105m
Option 3: More Ambitious Intervention	Net Present Social Value	-£80m	-£95m	-£105m
	Total Transfers	£815m	£910m	£1005m
	Total Costs	£80m	£95m	£105m

6. Costs and benefits to households' calculations

6.1. Counterfactual

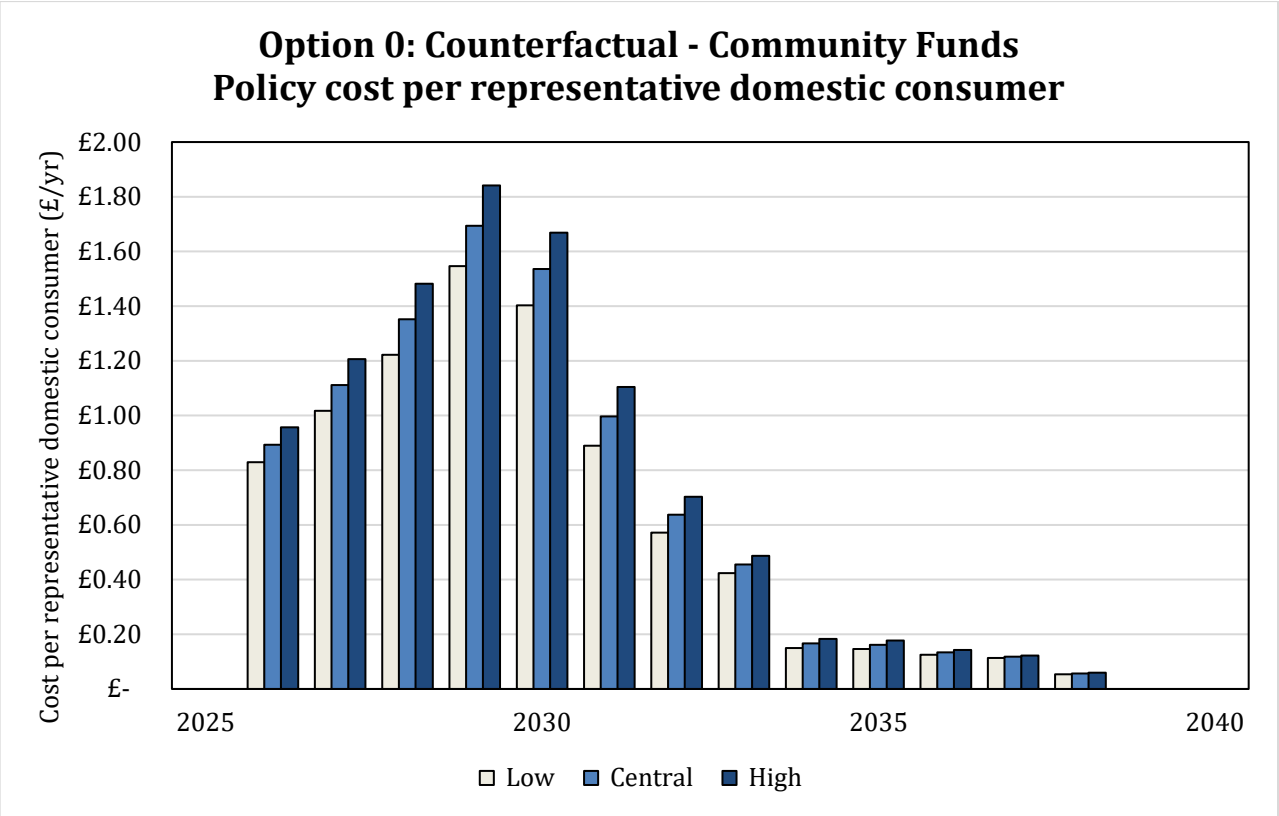
83. **Counterfactual:** The transfer costs and industry administration associated with community funds will be passed onto all electricity consumers via network charges. The mechanism for this will be managed by Ofgem and is expected to be on an annual pass-through basis. To estimate the potential cost impact for a typical domestic consumer, we have proportionally allocated the costs of the policy to each of the charging bands as set out in the latest NESO Transmission Network Use of System (TNUoS) tariff reports and forecasts.[78] Using the allocation of TNUoS fixed charges in 2025/26 as a benchmark, it is assumed that domestic consumers would fund approximately 38% of the total policy cost (including transfer values and administration costs). As these non-locational banded charges are a fixed tariff rate per site, the cost of funding the policy is the same for each domestic consumer regardless of consumption levels.

[77] Values presented for policy options 1 - 3 are to be read as absolute values, inclusive of costs and transfers under the counterfactual option.

[78] Domestic consumers are assumed to fund 38.1% of the policy cost, source: NESO: 2025-26 TNUoS Tariff Report (January 2025) and the total number of domestic meters this cost is distributed amongst is derived from NESO's 5-year site count forecast, source: NESO: Public 5-Year TNUoS Tariff (August 2025)- Table B: Non-locational banded charges.

84. Applying these assumptions, we have derived a total estimated cost associated with the counterfactual for a domestic consumer of £6.00 - £7.20 over the first 5-years of the policy or an annual average of £1.20 - £1.40 during this period.[79] Looking over the full appraisal period this is an aggregate cost of £8.50 - £10.20 and an annual average cost of £0.40 - £0.50. The peak in-year cost is estimated to be £1.60 - £1.90 in 2029. This is estimated to be broadly equivalent to a peak 1.3 – 1.6% increase in the total non-locational banded TNUoS tariff for the period considered.[80] Certainty in the pipeline of eligible infrastructure works reduces beyond 2030 as projects likely to take place in this period are of lower maturity and often insufficient details available for inclusion in cost modelling, therefore, the aggregate costs presented in this appraisal are likely to be an underestimate and the initial 5-year window is the preferred period for considering the potential cost impacts for consumers.

Figure 6.1: Option 0: Counterfactual – Voluntary Community Funds – policy cost per average domestic customer

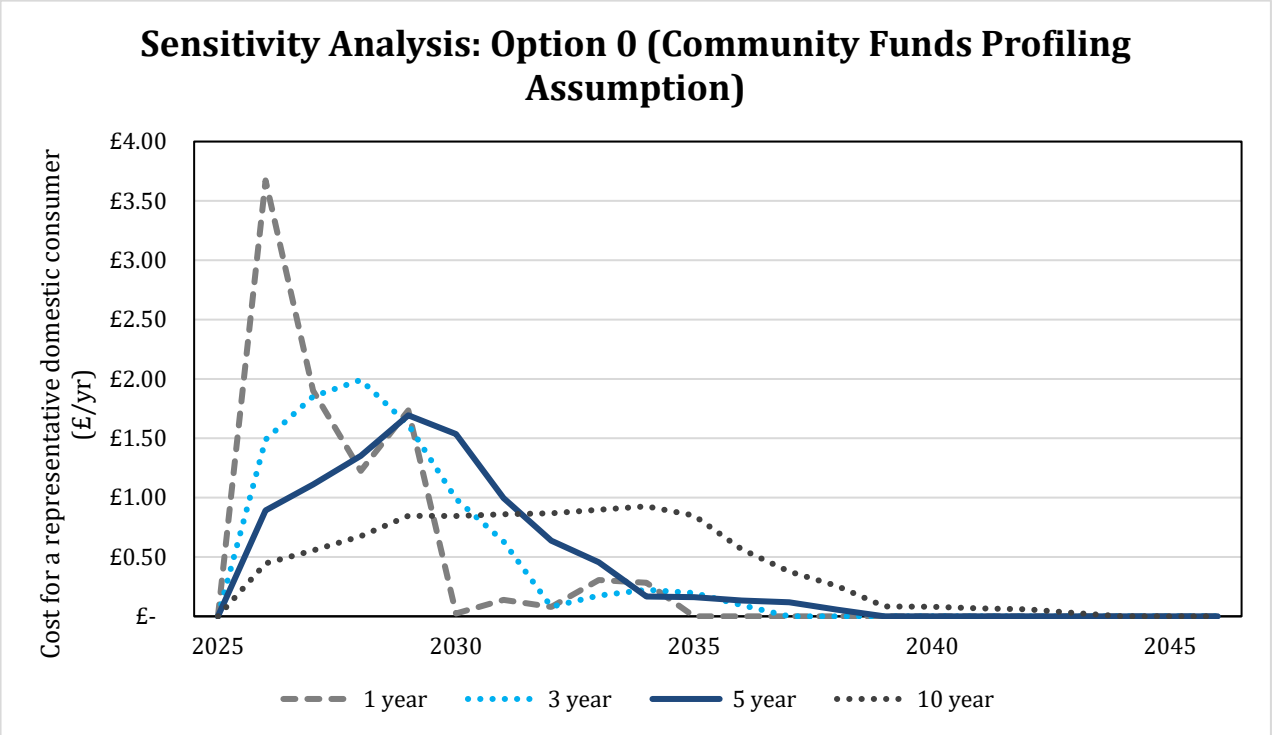


85. The profile of costs per consumer is sensitive to our assumptions on the period over which each individual community fund would be spent. The guidance stipulates that funds should be spent within a maximum of 15-years, however, following consultation with stakeholders at each of the TOs responsible for engaging community groups on this policy, a central assumption of 5-years to spend the funds

[79] All cost per consumer figures presented in this economic case are undiscounted and have been rounded to the nearest 10p. Therefore, estimated costs in nominal terms will be higher.
[80] Peak cost coming in 2029, proportion calculated against NESO: Public 5-Year TNUoS Tariff (August 2025)- Table B: Non-locational banded charges.

has been deemed an appropriate central estimate to apply in this analysis.[81] We have also tested the potential cost implications under both the quickest and slowest spend profile possible (i.e., 1-year and 15-years), which yields the range of possible cost profiles outlined in Figure 6.2 below.

Figure 6.2: Sensitivity Analysis: Option 0 (Community Funds) Profiling Assumption



86. The pace at which funds associated with the counterfactual are allocated will likely vary from project to project. A 1-year delivery scenario is assumed to be highly unlikely due to the amount of time TOs will require for establishing governance arrangements and consulting with the various stakeholders in each local community. Where local areas have an existing community action plan in place, funding could likely be allocated quickly, however, where the priorities of the host community are not clearly defined more time would likely be required to facilitate capacity building. The 15-year allocation scenario is also considered to be unlikely, given that the fund values are not indexed linked communities will be incentivised to spend upfront rather than spreading the amount over longer periods.

87. The benefits of transfer payments in the counterfactual are expected to benefit households in communities hosting transmission infrastructure, albeit indirectly, therefore for reporting purposes in this impact assessment they are classified as benefit to business, which includes voluntary and community organisations.

[81] Analysis of eligible strategic network investment projects considered in this analysis suggest an average construction period of 4-5 years.

6.2. Policy Options 1- 3: Proposed Bill Discount Scheme

88. The transfer costs, and a subset of defined industry administration and government administration costs associated with the proposed bill discount scheme will be funded by an obligation on all licensed electricity suppliers. It is assumed that these costs will be passed through fully to the customers of these suppliers, across both the domestic and non-domestic market. To provide an aggregate allocation of costs between domestic and non-domestic consumers we have proportionally allocated the costs of the policy using an assumed ratio of domestic electricity consumption as a proportion of total electricity consumption (approximately 38% in the first policy year) derived from DESNZ modelling.[82]

89. To estimate the cost for a typical consumer, we have first calculated the policy cost by dividing total annual policy costs by projected total annual electricity consumption, deriving an annual policy cost in £/MWh terms. This £/MWh policy cost is the unit cost to fund the scheme which is consistent for all electricity consumers. For the public minded-to position (Option 2) this policy cost is estimated to be £0.07-£0.09/MWh in the first policy year (2027) before rising to peak at £0.12-£0.15/MWh in 2029. To present this as a cost per average domestic consumer, we assume an average annual domestic electricity consumption rate of 3,400 kwh/yr, which yields the following estimated costs for the full appraisal period (Table 6.1).[83]

Table 6.1 – Policy Cost per average domestic consumer (full appraisal period)[84]

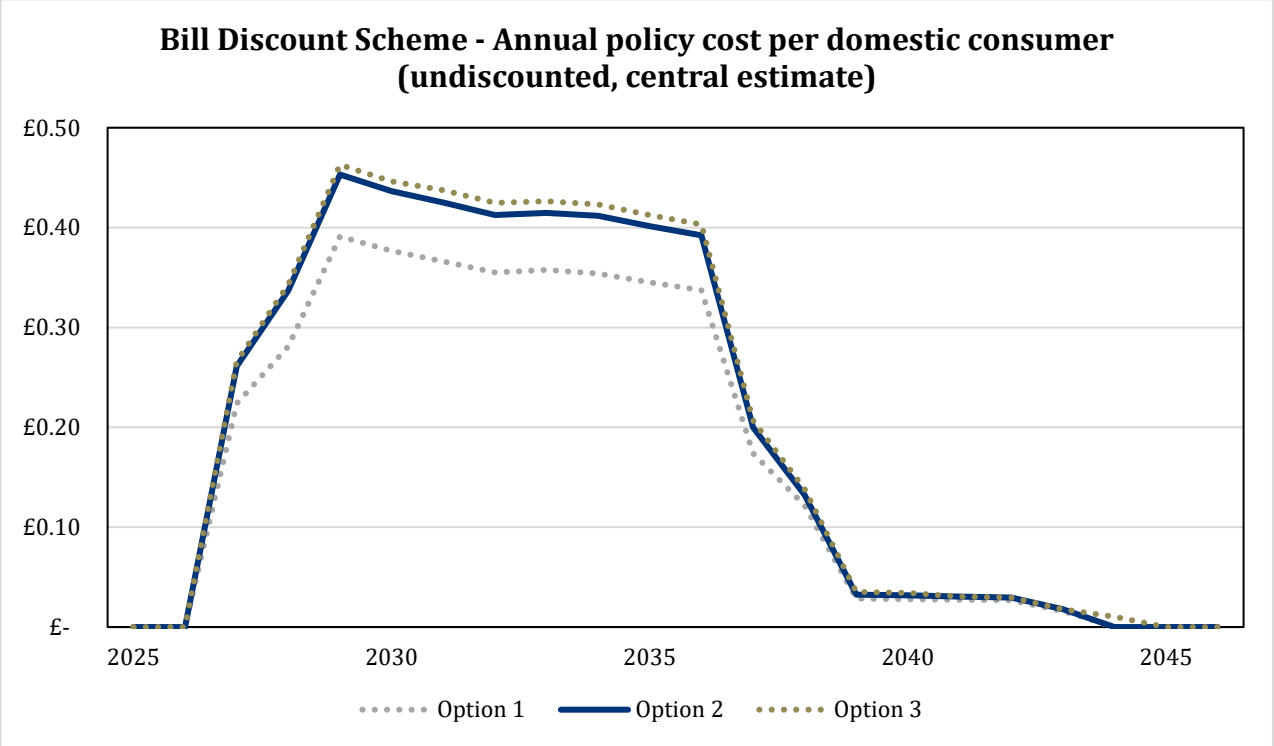
Policy Option	Total cost (2026 – 2044)	Annual average cost (2026-2044)	Peak in-year cost
Option 1: Less Ambitious Option	£3.30 - £4.30	~ £0.20	£0.30 - £0.40
Option 2: Preferred Option	**£3.80 - £5.10**	**~£0.20**	**£0.40 - £0.50**
Option 3: More Ambitious Option	£3.90 - £5.20	~£0.20	£0.40 - £0.50

[82] DESNZ: Energy & Emission Projects (EEP) 2023 – 2050 (December 2024). See reference case scenario in Annex F: Final energy demand in TWh

[83] Assumption derived from representative value used in DESNZ Quarterly Energy Prices publication, see Quarterly Energy Prices (September 2025) page 22.

[84] All consumer costs presented are undiscounted and rounded to the nearest 10p. Policy costs for Options 1 – 3 should be interpreted as additional to the counterfactual scenario.

Figure 6.3: Estimated Policy Cost (£/yr) for Options 1,2 and 3. Central estimate



90. The actual cost that licenced electricity suppliers would be able to pass onto domestic consumers will be subject to further analysis and consultation as part of Ofgem's price cap regime, and any analysis of potential impacts outlined here should be interpreted as indicative only.

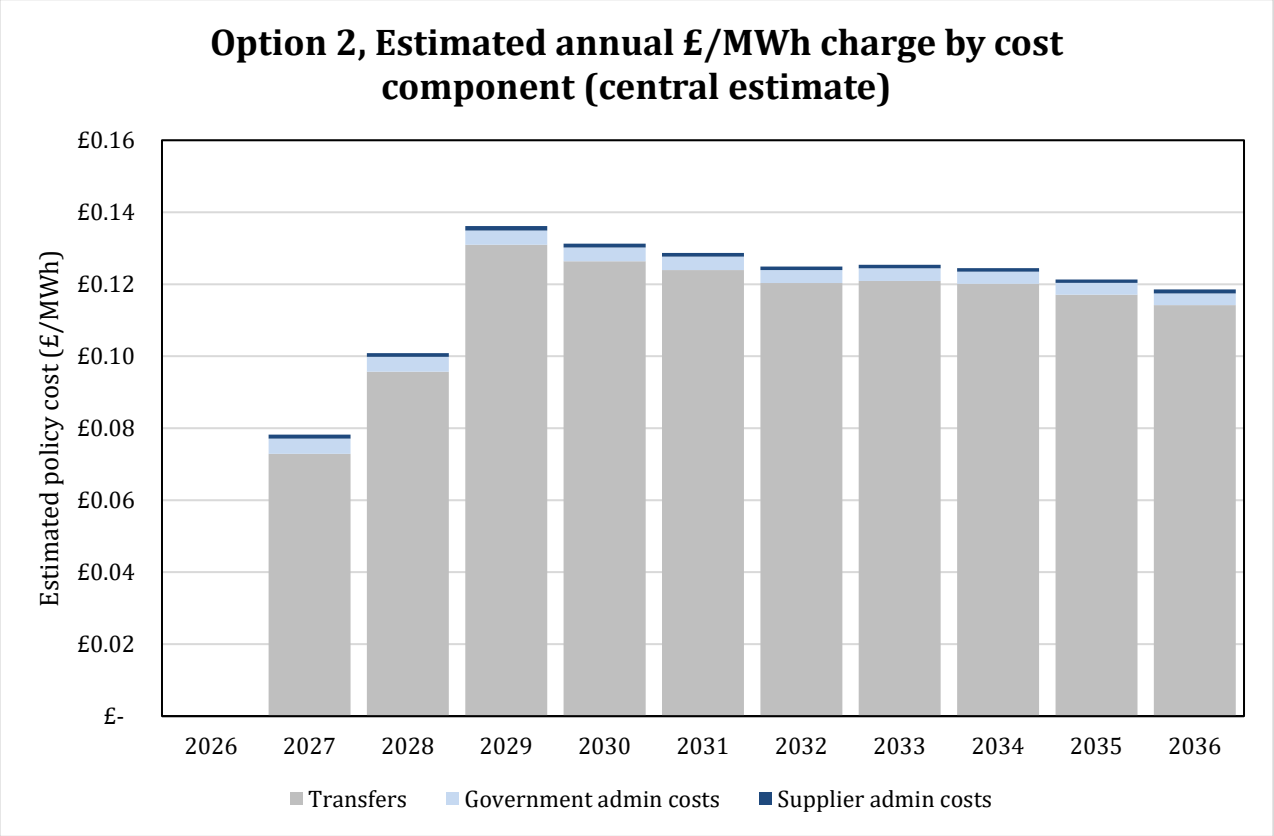
91. Transfers to eligible residential properties account for the bulk of the estimated policy cost (<95%) and Table 6.2 sets out the estimated breakdown of the £/MWh rate by cost component for Option 2. These cost components are also profiled in Figure 6.4 for the first 10 years of the policy. These £/MWh policy cost forecasts are presented as nominal, undiscounted figures, unless stated otherwise.

Table 6.2 – Estimated policy cost breakdown by component, Option 2

Bill cost component[85]	Average £/MWh (2027 – 2036)	Average % of policy cost (2027 – 2036)
Transfers	£0.114	96%
Government administration costs	£0.004	3%
Supplier administration costs	£0.001	1%

[85] Breakdowns are presented for the period 2027 – 2036 as these are the first 10 years where costs will be incurred by consumers. Beyond this point, certainty in the underling pipeline data of qualifying works is limited.

Figure 6.4 Estimated annual £/MWh charge by cost component, Option 2



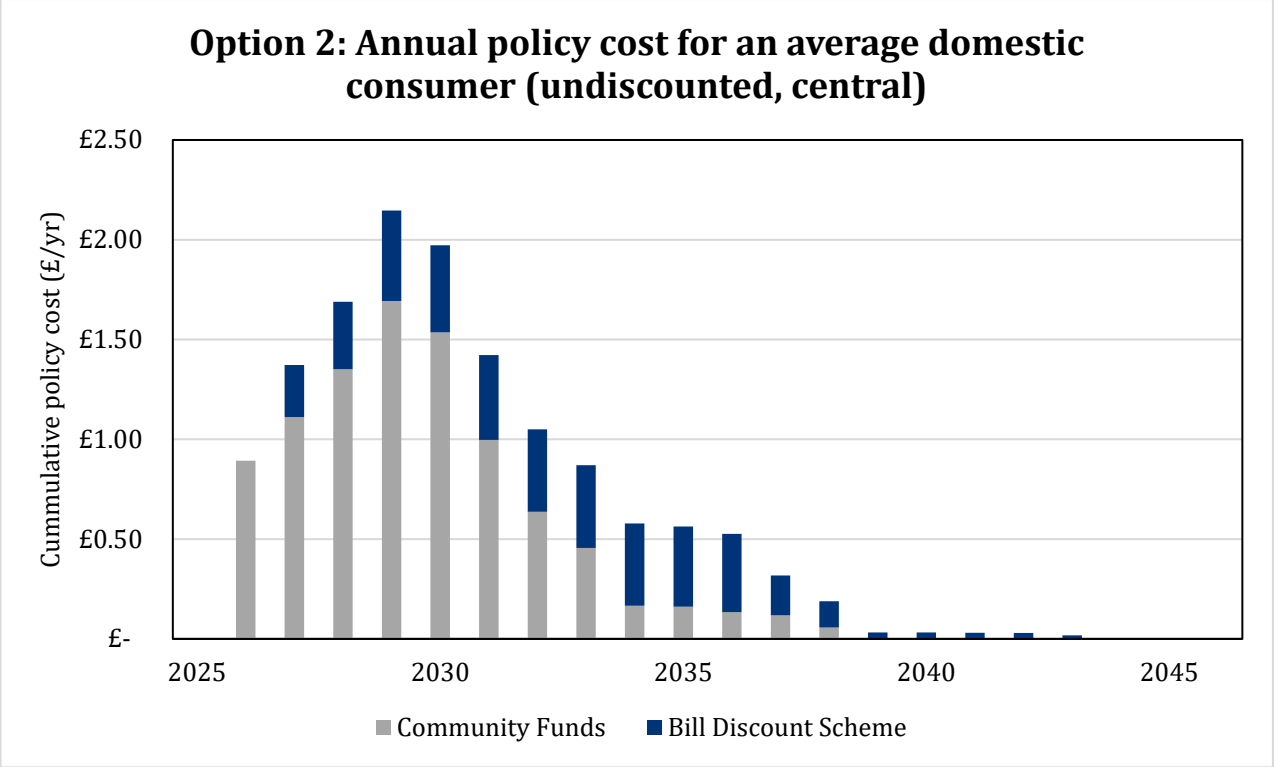
92. Given the preferred position of government is a dual approach combining guidance on community funds (Do Min/Option 0) and a mandatory bill discount scheme (Option 2), the cumulative cost of the proposed policy options is considered, as well as the additional cost of the sub-options which have been appraised. The cumulative estimated costs are set out in Table 6.2 for all options and displayed for the preferred option in Figure 6.4 below.

Table 6.3 – Cumulative policy cost per average domestic consumer[86]

Policy Option	Total cost (2026 – 2044)	Annual average cost (2026-2044)	Peak in-year cost
Option 0: Counterfactual	£8.50 - £10.20	£0.40 - £0.50	£1.60 - £1.90 (Year 2029)
Option 1: Less ambitious intervention	£11.90 - £14.50	£0.60 - £0.70	£1.90 - £2.30 (Year: 2029)
Option 2: Preferred Option	£12.40 - £15.20	£0.60 - £0.70	£1.90 - £2.40 (Year: 2029)
Option 3: More ambitious intervention	£12.50 - £15.40	£0.60 - £0.70	£2.00 - £2.40 (Year: 2029)

[86] All costs presented are undiscounted and rounded to the nearest 10p. Policy costs for Options 1 – 3 are displayed here as a combined cost with the do minimum option.

Figure 6.4 Estimated Cumulative cost per average household, central estimate, preferred option



93. The benefits of transfer payments in the policy options are expected to benefit households in communities hosting transmission infrastructure exclusively, as eligibility is limited to residential properties only. Businesses see an overall cost while households see an overall benefit. At the level of social welfare, these net of.

94. As outlined in section 5.4, there are also potentially significant non-monetised benefits to all electricity consumers, if this policy supports the wider departmental objective of enabling an accelerated deployment of transmission network infrastructure by 2030. Analysis by NESO and Ofgem estimates the potential benefit in 2030/31 for a typical dual fuel household to be approximately £55.[87] However, we have not quantified the extent to which these policies may support this benefit being realised, for the reasons outlined in Section 5.4.

7. Costs and benefits to business calculations

95. The vast majority of costs associated with both the counterfactual and proposed policy options under consideration will be passed through to electricity consumers via two mechanisms. We have disaggregated the costs associated with these options for

[87] Ofgem RIIO-3 Draft Determinations – Impact Assessment, 5.14 – 5.18.

both businesses and households, in aggregate terms and for a l household with average annual consumption.

7.1. Counterfactual

96. In the counterfactual scenario, the costs of facilitating and administering the transfer payments to eligible communities is incurred directly by licenced Transmission Owners (TOs) in Great Britian. However, given the ability for TOs pass-through these costs it is assumed that the remaining 62% of policy costs not covered by domestic consumers (as outlined in 6.1 above) will be passed onto non-domestic electricity consumers.

97. Given the heterogeneity of consumption in the non-domestic sector, charging arrangements are more complex than for domestic consumers. Therefore, it is not as simple to provide a representative cost for a "typical" non-domestic electricity consumer. However, as we anticipate the costs associated with counterfactual will be passed on via the fixed non-locational tariff element of TNUoS charges, we're able to apply the 2025/26 NESO TNUoS cost allocations and 5-year TNUoS forecast assumptions to estimate the potential costs for non-domestic non-half hourly metered consumers in the following consumption bands. These non-half hourly metered consumers account for approximately 90% of the non-domestic market by site/MPAN count.[88]

Table 7.1 Option 0: Counterfactual (Voluntary Community Funds) – Policy Cost for Non-Half Hourly Metered Non-Domestic Consumers

Consumption Band	Total cost (2026 – 2044)	Annual average cost (2026-2044)	Peak in-year cost
Very Small Annual Consumption: LVN1 (< 3,571 kwh/yr)	£10 - £12	£0.50 - £0.60	£1.80 - £2.20
Small Annual Consumption: LVN2 (< 12,553 kwh/yr)	£24 - £28	£1.10 - £1.30	£4.30 - £5.10
Medium Annual Consumption: LVN3 (< 25,279 kwh/yr)	£51 - £61	£2.40 - £2.90	£9.30 - £11.10
High Annual Consumption: LVN4 (> 25,279kwh/yr)	£141 - £168	£6.70 - £8.00	£25.70 - £30.60

7.2. Policy Options 1-3: Proposed Bill Discount Scheme

98. In the proposed bill discount scheme, the costs of facilitating and administering the transfer payments to eligible households is incurred directly by licenced electricity suppliers in Great Britain. However, these suppliers are anticipated to pass on costs

[88] Calculation based on data in NESO 2025-26 TNUoS Tariff Report (January 2025) – Annex Table B – Non-locational banded charges.

to all customers across both domestic and non-domestic markets, as outlined in section 6.2 above, with approximately 63% of policy costs expected to be passed onto non-domestic consumers in the first policy year.[89]

99. As mentioned in section 7.1 above, non-domestic electricity consumption is much more variable compared to the domestic sector, therefore, it is not as helpful to present results for a "representative" business consumer. However, we have calculated the % increase in the forecast unit rate for supply of electricity to industrial and commercial consumers implied by the policy costs of each option, which are displayed in Figure 7.1 below.[90]

Figure 7.1: Annual Profile of Option 1 - 3 Policy Cost (£/MWH)

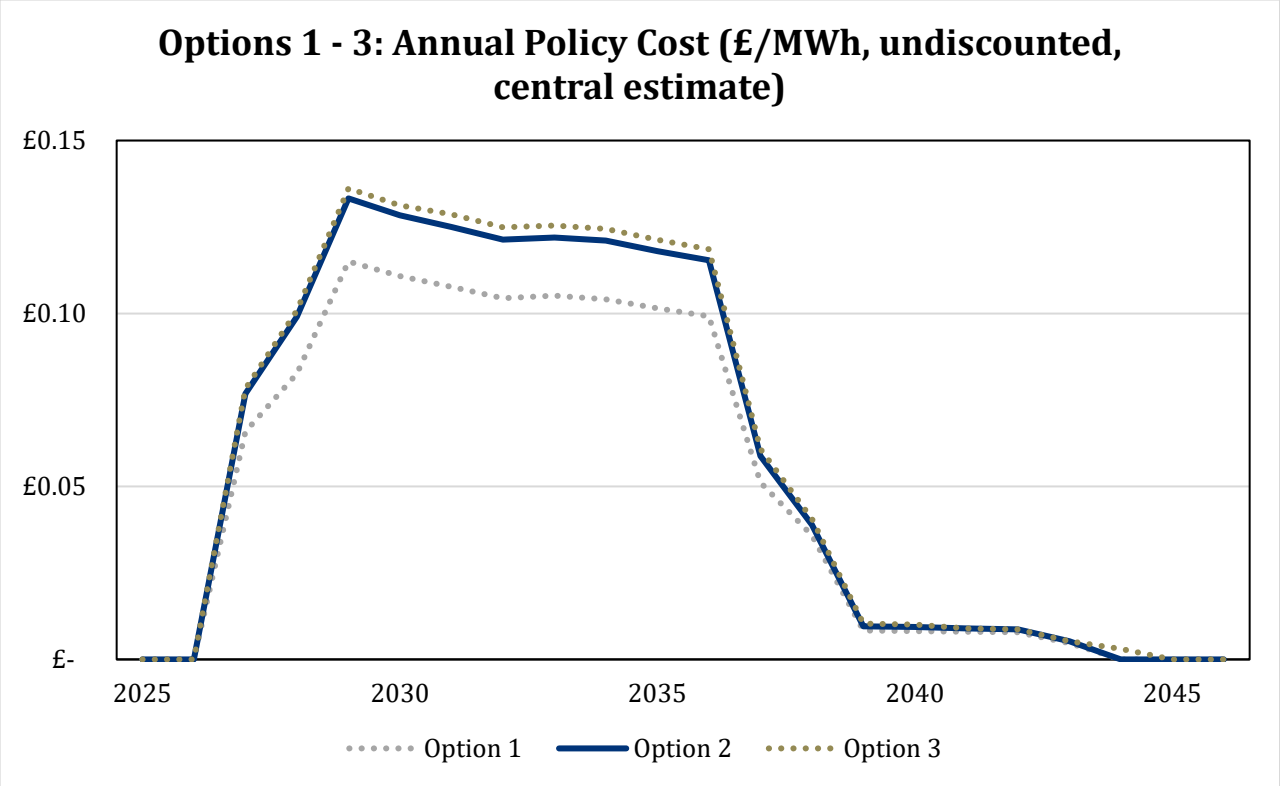
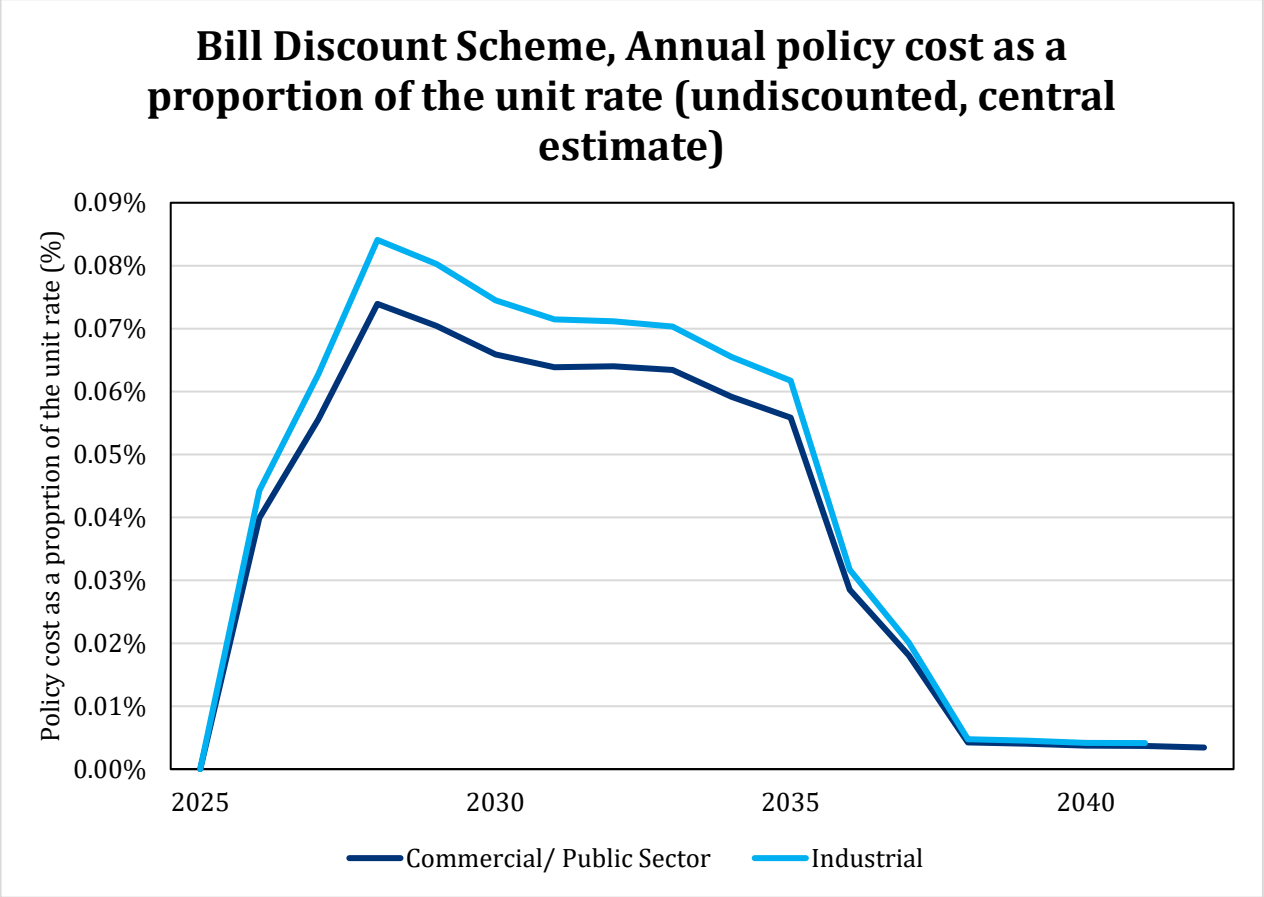


Figure 7.2: Annual profile of preferred option policy cost (£/MWH/yr) as an implied % uplift on unit rate for non-domestic electricity consumers

[89] The assumed ratio of pass through between domestic & non-domestic consumers is calculated on an annual basis as the ratio of domestic and non-domestic consumption in the EEP (2023-2050) Reference Case.

[90] Forecast retail unit rates, as set out in DESNZ supplementary guidance to HM Treasury Green Book, rebased to 2025 prices.



7.3. Energy Intensive Industries (EII) Exemption

100. The government's current preferred position is to exclude Energy Intensive Industries (EIIs) from the obligation to fund the proposed scheme. A proportionate approach to accounting for this in our appraisal has been discussed with analysts at the Department for Business & Trade. An assumption for aggregate electricity consumption from businesses in receipt of the British Industry Supercharger (BIS), the existing support scheme for EIIs has been used as a proxy.[91] This value is netted off from our aggregate electricity consumption figure before the policy cost (£/MWh) calculation to reflect the reallocation of EIIs cost contribution onto all other electricity consumers.

8. Impact on small and micro businesses

101. The direct costs of both the counterfactual and policy options considered in this appraisal are incurred by licenced Transmission Owners (TOs) and electricity suppliers. The TOs considered in scope of these policies are not small or micro businesses so have not been subject to further assessment. An assessment of the

[91] This is estimated at approximately 4.5% of total GB electricity consumption, see the 2024 British Industry Supercharger Impact Assessment for further details on eligibility criteria for EII exemption.

potential impact on licenced electricity suppliers has been carried out by matching unique Company Reference Numbers (CRNs) as listed in Ofgem's official register of licenced electricity market participants to company records in the Inter-Departmental Business Register (IDBR). [92,93]

102. Initial results from this analysis suggest that of the 19 electricity suppliers active in the domestic market and assessed in this appraisal, 1 supplier could be classed as a micro business, and 1 supplier could be classed as a small business, as per the employment definitions set out in the Better Regulation Framework and RPC guidance. [94,95]

103. It would not be possible to achieve the intended policy objectives by exempting small and micro businesses electricity suppliers from their obligation in this scheme, as this may lead to some eligible households potentially missing out because of their choice of supplier. It has also not been considered feasible or proportionate to exclude non-domestic electricity consumers from funding the policy costs incurred by the proposed scheme, whether they be small, micro businesses or otherwise, as this would lead to a significant increase in the policy costs borne by domestic electricity consumers. Analysis suggests exclusion of the non-domestic market from the obligation to fund policy costs would result in a x3 times increase in cost per average domestic consumer and funding the policy via a fixed charge per meter point rather than a volumetric charge would result in a similar re-distribution of the cost burden from non-domestic to domestic consumers.[96] Furthermore, all electricity consumers – regardless of whether they are domestic or non-domestic – benefit from the role communities play in hosting transmission network infrastructure.

104. By facilitating transfer payments there is a potential risk that some suppliers, with smaller market shares could be exposed to negative cashflow risk, particularly if their customer base are disproportionately represented in the population of eligible households.[97] However, without access to MPAN data we have not been able to link eligible UPRNs identified in our analysis to suppliers and therefore are unable to assess the extent to which this risk is material. Potential mitigations include considerations about the process and timings for reconciliation of funds, and amount of notice provided to suppliers to amend billing processes and collect funds in

[92] Ofgem: List of all electricity licensees including suppliers

[93] ONS: Interdepartmental Business Register (IDBR)

[94] Ofgem: Retail Energy Market Indicators. Note: Rebel energy ceased operations in April 2025, hence the total reducing from 20 (as listed by Ofgem in March 2025) to 19.

[95] DBT (2023): Better Regulation Framework Guidance. Annex 3: Small, micro and medium business assessments

[96] Analysis based on assumed proportion of electricity market share by consumption of ~37% domestic and 63% non-domestic, compared to a market share by meter points (i.e., site count) of 92% domestic and 8% non-domestic. Sources; DESNZ Energy & Emission Projects (EEP) reference case and NESO; 2025-26 TNUoS, non-locational banded tariffs.

[97] As flagged in Ofgem's response to the DESNZ (2025) Consultation on scheme design for bill discounts for new transmission network infrastructure

advance. Ongoing monitoring of this risk should be carried out as the scheme progresses.

9. Business environment

105. If the policy interventions considered in this appraisal deliver on their intended impact, this may enable and support licenced TOs in delivering significant investment in the electricity transmission network for Great Britain. The total level of investment expected over the RIIO-3 period (2026-2031) is estimated to reach £70 billion in aggregate across the three licences areas of GB.[98]

10. Trade implications

106. The policy options considered in this appraisal are not anticipated to have any significant trade implications given the relate predominately to transfers from all electricity consumers to households and communities in areas of Great Britian hosting new transmission network infrastructure.

11. Environment: Natural capital impact and decarbonisation

107. Community funds generated in the counterfactual scenario (Option 0) could be spent on local environmental schemes; either through direct improvements to the local natural environment, or indirectly through investments to improve energy efficiency of local properties or investments in community owned micro-generation. These investments could yield significant environmental or natural capital benefits – but have not been quantified as it is at the discretion of licenced TOs and local communities to collectively decide how funds are spent, and any assumptions applied here would be arbitrary.

108. For the other policy options considered (Options 1 – 3: Proposed bill discount scheme) as the vehicle for transferring funds is via eligible households' electricity bills, it is plausible that there may be a behavioural response from households in terms of increasing their consumption of electricity, with potential emission consequences. This is a commonly observed impact in the context of energy efficiency improvements and referred to as "rebound effects" or "comfort taking".[99] However, the extent to which this materialises is uncertain, and dependent on the marginal elasticity of demand for electricity of eligible households. As the primary motivation for this policy is not to encourage a specific behavioural response with regards to energy consumption, it has not been deemed proportionate to quantify any potential impacts associated with this.

[98] Ofgem (2025): RIIO-3 Final Determinations Impact Assessment Note: Not all of the investment outlined in this aggregate figure would be supported by these policy interventions, as some will account for investment out of scope of the proposed scheme.

[99] As outlined in Sections 3.8 – 3.14, DESNZ supplementary guidance to HM Treasury Green Book

109. If the range of policy options considered do support a reduction in network constraint costs, as outlined in section 5.4, this would likely have emissions implications, because when the transmission network is constrained, renewable generation is usually curtailed (switched off) whilst non-renewable generation is usually switched on to meet demand. These impacts have not been quantified due to the points outlined in 5.4.

12. Other wider impacts

12.1. Distributional Analysis – Funding of Policy Options 1-3: Bill Discount Scheme

110. As consumption of electricity is correlated to income, the costs of funding this policy is not likely to be uniform across all households in GB. To test, the distributional impact of funding the scheme more formally, we have applied an assumed adjustment rate by calculating the divergence from average weekly household expenditure on electricity for each income decile, using data published by the ONS.[100] This income-decile adjusted calculation yields the following adjusted costs of funding the proposed policy. As the results in Table 12.1 show, this distributional impact is expected to be limited.

Table 12.1 – Additional policy costs for domestic consumers - by income decile

Policy Option	Lowest Income Decile	Highest Income Decile
Option 1	**Total (2026 – 2044):** £11.60 - £14.20 **Max annual:** £1.90 - £2.30	**Total (2026 – 2044):** £12.40 - £15.20 **Max annual:** £1.90 - £2.40
Option 2 (Public minded-to-position)	**Total (2026 – 2044):** £12.10 - £14.90 **Max annual:** £1.90 - £2.30	**Total (2026 – 2044):** £12.90 - £16.00 **Max annual:** £2.00 - £2.50
Option 3	**Total (2026 – 2044):** £12.20 - £15.00 **Max annual:** £1.90 - £2.30	**Total (2026 – 2044):** £13.10 - £16.20 **Max annual:** £2.00 - £2.50

[100] Source: Family Spending Table 3.1E: Detailed household expenditure by equivalised disposable income decile group (OECD-modified scale). An average variation from mean by decile has been calculated for values covering the past 5-years of published data (FYE 2020 – 2024)

12.2. Distributional Analysis – Beneficiaries of Policy Intervention

111. Initial distributional analysis, to assess the socio-economic characteristics of areas likely to be in receipt of transfer payments under the proposed policy intervention has been carried out, utilising geospatial data of eligible infrastructure projects which has been made available for this appraisal. It is worth noting that this distributional analysis is based on the relevant statistical geographies of areas intersected by transmission projects identified as eligible in our pipeline, so is reflective of the broader areas where eligible households are likely to reside, rather than being representative of eligible households directly. We have considered measures of deprivation and protected characteristics such as age and ethnicity in this initial appraisal. The source data for socio-economic variables includes 2021 census data for England & Wales and 2019 English Indices of Multiple Deprivation (IMD). [101,102]

Protected Characteristics

112. **Age:** Analysis of census data at Middle Layer Support Output Area (MSOA) suggests that residents in areas likely to host transmission infrastructure included in our appraisal are likely to be slightly older than the rest of the population, with 20.3% of the sample population aged 65 and over compared to the national average of 18.7%.

113. **Race**: Analysis of census data at MSOA, suggests that residents in areas likely to host transmission infrastructure included in our appraisal are more likely to identify as White (89.3%) relative to the rest of the population (82.6%).

114. **Disability:** Analysis of census data at MSOA, suggests that households in areas likely to host transmission infrastructure included in our appraisal have a similar likelihood of having at least one resident who is disabled under the Equality Act 2010 (33.6%) relative to the population (32.2%).

115. We did not have sufficient data to assess whether the eligible population has a different distribution of other protected characteristics (sex, religion or belief, sexual orientation, pregnancy and maternity, gender reassignment, marriage and civil partnership, or other relevant demographics) compared with the population. However, a full qualitative assessment of all protected characteristics has been carried out in line with the requirements of the public sector equality duty, as set out in the Equality Act 2010.

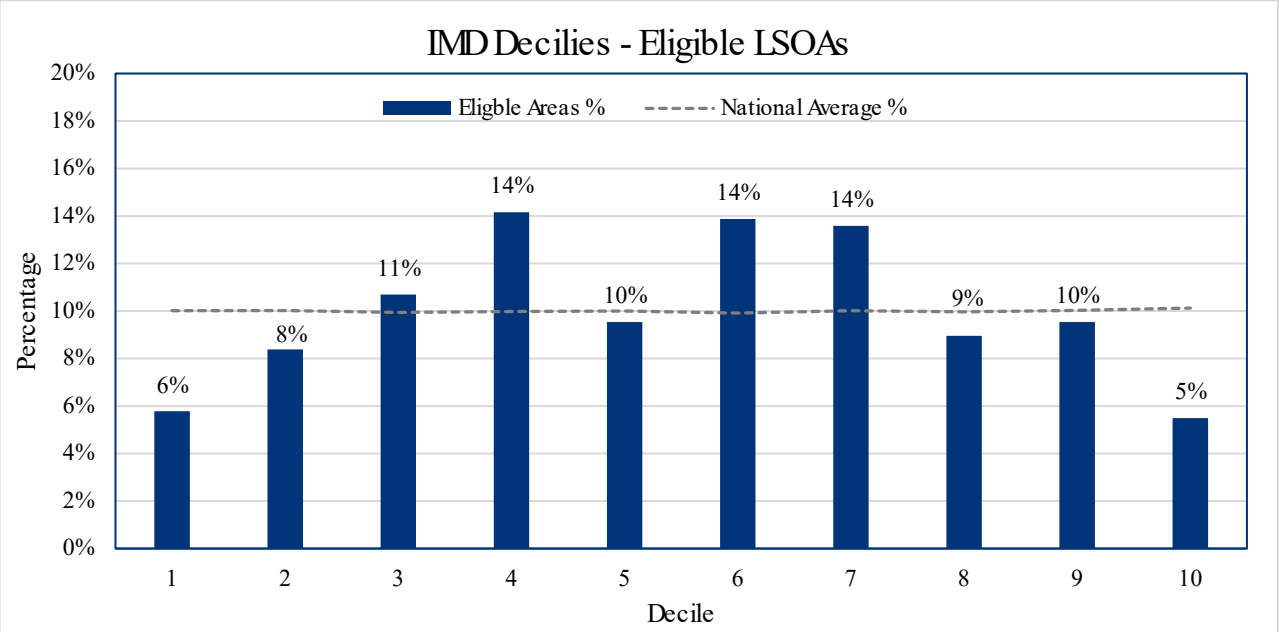
116. **Deprivation***:* Analysis of IMD data for England, provided at the Lower Super Output Area (LSOA) level, incorporates seven domains of deprivation: income, employment, education, skills and training, health and disability, crime, barriers to housing and services, and living environment deprivation. The findings suggest that areas identified in our analysis as likely to be hosting transmission network infrastructure are not uniformly distributed across deprivation deciles. Instead, they

[101] ONS: England and Wales: Census 2021

[102] MHCLG (2019): English indices of deprivation

demonstrate a higher concentration in middle deciles (3-7). Notably, areas identified as likely to benefit from this policy intervention are underrepresented in both the most deprived areas (6% in decile 1) and least deprived areas (5% in decile 10).

Figure 12.1 – Share of population by Index of Multiple Deprivation (IMD) decile in LSOAs of potentially eligible areas identified in our appraisal relative to the national distribution.



117. **Fuel Poverty:** There is a potential positive interaction between the introduction of the proposed policy intervention and fuel poverty rates in Great Britian, although this has not been formally quantified, due to the uncertainty in identifying eligible households. It is anticipated that a significant number of eligible properties considered in the policy intervention will be in predominantly rural areas. In England, households living in rural areas had the highest fuel poverty rate of 12% and the largest fuel poverty gap at £987.[103] While, in Scotland the fuel poverty rate for rural households is 35%, rising to 44% for dwellings in remote-rural areas, and in Wales 26% of rural households are estimated as experiencing fuel poverty. [104]

118. Note that each of the constituent nations of Great Britain utilise different methodologies to estimate fuel poverty, therefore, these rates are not directly comparable but emphasise that if as anticipated, the proposed policy intervention largely benefits rural households, then there is likely to be a potential positive interaction.[105]

[103] DESNZ (2025): Annual Fuel Poverty Statistics in England, (2024 data).The fuel poverty gap is a measure of the additional fuel costs (in pounds) faced by fuel poor households compared with the required fuel costs at the threshold that would make them non-fuel poor.

[104] Scottish Government (2025): Scottish House Condition Survey: 2023 Key Findings; Welsh Government (2025): Fuel poverty modelled estimates for Wales: as at October 2024

[105] See, ONS: How fuel poverty is measured in the UK: March 2023 for further details on the methodological differences.

13. Risks and assumptions

(1) Risk that this appraisal has underestimated potential policy costs:

119. As outlined in previous sections, an accurate appraisal of these policy interventions is reliant on the availability of accurate data from TOs on pipeline of eligible works. Quality of data provided for strategic network investment projects is likely to be of sufficient quality to have a reasonable degree of confidence in the appraisal. However, significant data gaps associated with the extent of enabling works for customer connections remain, due to the uncertainty associated with grid connection reform, which we have attempted to account for with a proportionate approach. Once the grid connection reform process has been completed and new transmission connection agreements have been issued, a more accurate assessment of the potential pipeline of projects can be carried out. It is therefore, highly likely that the accuracy of cost & transfer forecasts outlined in this appraisal will diminish in the later years of the appraisal period due to a lack of certainty of eligible infrastructure projects which are of low maturity and yet to engage with the planning process – with the likely consequence that cost & transfer values are underestimated.

120. Similarly, the costs estimate for Options 1-3: proposed bill discount scheme, are heavily reliant on the availability of accurate geospatial data for qualifying works. This data has proven difficult to obtain due to the low maturity level of several projects considered in this appraisal. Assumptions have been utilised to fill in gaps, but an accurate cost appraisal would only be possible with access to detailed geospatial data for the proposed routes.

121. Reflecting the level of uncertainty attached to key data underpinning this appraisal, a +/- 20% sensitivity adjustment has been applied to central estimates for the number of eligible households, the key driver of transfer values/costs in the preferred policy option. This has been supplemented by an additional +10% optimism bias adjustment to account for any residual uncertainty and risk in the underlying pipeline data of eligible infrastructure projects.[106]

(2) Risk that policy proposals have no impact or unintended consequences:

122. The intended impact of the proposed policies considered in this business case is to support an improvement in acceptance of transmission infrastructure amongst residents most likely to be impacted. There is some evidence which suggests that the provision of a benefit, whether it is distributed collectively to the community or in the form of direct transfers to individual households may support this objective.

[106] Optimism bias is the demonstrated systematic tendency for appraisers to be over-optimistic about key project parameters, including capital costs, operating costs, project duration and benefits delivery. The primary driver of residual uncertainty is the potential underestimation of eligible transmission infrastructure projects, and there is little to no empirical evidence on which to base a judgement for the potential scale of underestimation. Further analysis will, be carried out on the potential gaps in this data, and this optimism bias adjustment will be kept under review.

However, the wider field of academic literature presents more nuanced findings, some of the key points are presented here.

A. Boundary Impacts of the proposed bill discount scheme:

123. Evidence from the pilot evaluation of the Irish Grid operator (EirGrid) community benefit fund, found that relying on objective distance thresholds often led to unintended and inequitable consequences.[107] In one case, an entire settlement was split arbitrarily due to a proximity measure, with households on one side of a street qualifying for community benefits while neighbours just metres away on the other side of the street did not. Proximity is also likely to be an imperfect measure of impact as it fails to account for local topography.

124. There is a potential risk that a policy intervention based on fixed distances as the main qualifying criterion, could cause unintended conflict within communities and between communities and grid operators, reducing community acceptance of new transmission infrastructure. This risk is potentially amplified by absence of any tapering of benefit levels, creating a starker gap between recipients and non-recipients at the boundaries. Further evidence from the EirGrid pilot, suggests that fairer outcomes arise from dialogue with the host communities, with distance and visual impact considered as a starting point but not a determining factor.[108] These principles have been adopted in the counterfactual (Option 0: voluntary community funds) with the guidance not prescribing any distance based criteria.[109] However, this has not been considered feasible in the design of the proposed bill discount scheme due to concerns about the practical deliverability, of such approaches.[110]

B. Framing of community benefits:

125. Extensive academic literature highlights that perceptions of community benefit arrangements significantly influence their effectiveness, with a consistent theme that such solutions are not always universally applicable. Empirical evidence from Switzerland shows that direct payments linked to a proposed nuclear facility halved local support, explained by the authors as due to the compensation being perceived as bribery, which led to a 'crowding- out' of residents' altruistic motives. [111,112]

126. Similar dynamics are observed in the UK, where the framing and timing of offers affect their reception. Cass et al. (2010) found that while developers frame benefits as corporate social responsibility, communities are more likely to view them negatively—especially if offered before consent (offer seen as conditional on

[107] Devine-Wright and Sherry-Brennan (2017). EirGrid Pilot Community Fund Evaluation Report
[108] Devine-Wright and Sherry-Brennan (2019). Where do you draw the line? Legitimacy and fairness in constructing community benefit fund boundaries for energy infrastructure projects
[109] For further details see Chapter 5. Identifying eligible communities in Community Funds for Transmission Infrastructure: Guidance.
[110] The proposed policy position for the bill discount scheme includes the scheme administrator identifying potential edge cases where the geometry linked to a UPRN sits outside the eligibility zone, but the actual property boundary is within. However, this would not mitigate the full impact of this risk.
[111] Frey et al. (1996): The Old Lady Visits Your Backyard: A Tale of Morals and Markets. Results show acceptance rates among respondents falling 50.8% to 24.6% with the introduction of direct financial compensation.
[112] Frey and Oberholzer-Gee (1997): The Cost of Price Incentives: An Empirical Analysis of Motivation Crowding Out.

support) or after (offer seen as compensation for implicit damage).[113,114] Notably, results from both studies suggest that benefits perceived as collective in nature or mandated, rather than individual and voluntary, reduced the perceived bribery effect.[115,116] This has led to suggestions from other authors that society-wide community benefit arrangements offer a more appropriate delivery mechanism—a viewpoint which has been echoed in consultation responses from some electricity suppliers and transmission operators.[117,118] Potential mitigations include clear and consistent messaging from government and industry stakeholders on the motivation for provision of community benefits, to counteract the potential risk of negative perceptions.

C. **Risk of persistent local opposition being resistant to policy intervention:**

127. Evidence from social research indicates that there is likely to be a core group of local opposition to transmission infrastructure, with views that are fixed and unlikely to be altered by any of the policy interventions considered. Around one in ten (6% - 13%) of respondents in DESNZ commissioned social research said no amount of direct payment or community funding would help them find the transmission infrastructure more acceptable.[119] This is supported by similar research in Ireland, which reported significantly higher numbers of residents (~40%) having fixed views which would be resistant to community benefit interventions, and is a sentiment which has played out in some of the initial public reactions and reporting following the policy announcement in March 2025. [120,121]

(3) Risk that alternative interventions could be more cost-effective:

128. Evidence from existing social research suggests that factors other than the provision of community benefits - either as direct payments to households or collectively to the community - may be more effective at improving community acceptance of transmission infrastructure. Cohen et al (2016), carried out an empirical analysis of community acceptability of grid infrastructure across EU-27 nations and found that provision of information about the economic & environmental benefits of transmission infrastructure was likely to be more effective than financial compensation.[122] This is supported by findings which from recent DESNZ social research, which found that information provided to respondents about the local economic benefits of transmission projects, such as employment opportunities in their local area elicited a more significant increase in acceptance levels relative to other themes which were tested - including community benefits (in the form of bill

[113] Cass et al. (2010): Good Neighbours, Public Relations and Bribes: The Politics and Perceptions of Community Benefit Provision in Renewable Energy Development in the UK.
[114] The provision of a community benefit fund or payment to residents is not legally allowed to be a 'material consideration' in the planning process.
[115] Cass et al. (2010), ibid.
[116] Frey et al. (1996), ibid.
[117] Tobiasson and Jamasb (2016): The Solution that Might Have Been: Resolving Social Conflict in Deliberations about Future Electricity Grid Development.
[118] DESNZ (2025) Consultation on scheme design for bill discounts for transmission network infrastructure. Responses to question 19: Do you agree with the rationale for intervention and the market failures we have identified?
[119] DESNZ (2024) Research and analysis – Community benefits for electricity transmission network infrastructure.
[120] Hyland and Bertsch (2017): The role of community involvement mechanisms in reducing resistance to energy infrastructure development
[121] BBC News (27th March 2025): Pylon bill discounts an 'insult' to residents
[122] Cohen et al. (2016): An Empirical Analysis of Local Opposition to New Transmission Lines Across the EU-27

discounts). This is partly explained by a high proportion of respondents in the community benefit treatment group (50%) did not trust the information provided to them about proposed bill discounts to be true and hence delivering a smaller impact on acceptance as a result, with an 8 percentage point (ppt) increase for the community benefit treatment group, compared to 11ppts for the economic benefit group.[123]

129. Community benefit interventions, either in a collective offer or directly to individuals may support an increase in acceptability of transmission infrastructure, however, there are multiple factors which may result in the proposed policies not delivering upon the intended benefits they aim to achieve – underlining the importance of a comprehensive M&E programme to understand the effectiveness of the policies once implemented.

14. Monitoring and Evaluation

130. We will monitor and evaluate the bill discount scheme's delivery and its impact on communities across the country, alongside the implementation of community funds guidance, to understand the effect community benefits may have on building community acceptance for local infrastructure and reducing delays to transmission network build.

131. The monitoring and evaluation approach will utilise operational data alongside insights from scheme participants and wider stakeholders to understand how effectively the scheme is being delivered, provide early learnings to improve the scheme's delivery, and understand the impact of the scheme on communities across the country.

132. We are conscious that this is a novel scheme and will hold two review points within the first 5 years of its delivery to gain a detailed understanding the scheme's roll-out, and provide opportunity for early learnings, improvements, course correction or close the scheme earlier than intended, to mitigate against any unintended or negative effects of the scheme.

133. The evaluation plan will be based on the following key objectives:

A. To assess whether the implementation of CFs and the BDS was delivered as intended.
B. To assess whether both schemes had an impact on the attitudes and perceptions of communities, in particular communities feeling they have been recognised, perceptions of fairness and community acceptability of local transmission network infrastructure.

[123] DESNZ (2025): Public attitudes to network infrastructure: an online experiment testing rationales for building new network infrastructure.

C. To assess whether both schemes are contributing to (as part of a combination of policy measures) accelerated deployment and/or avoided delays of transmission infrastructure.
D. To assess whether both schemes were a good use of resources and to assess whether both schemes were designed in an effective and efficient way to achieve their stated objectives.
E. To inform future decisions about course-correction or the continuation of the BDS and inform future government policy around community benefits.

134. The evaluation programme will include both process and impact components:

135. **Process evaluation:** The process evaluation will explore scheme delivery, including communication, accessibility for hard-to-reach households and the administrative burden on suppliers and delivery partners. The process evaluation will combine scheme administrative data with primary research (such as interviews with key stakeholders and eligible households) to provide early insights to support scheme delivery.

136. **Impact evaluation:** The impact evaluation focuses on changes in community attitudes, satisfaction with the scheme, and its role in reducing legal challenges.

137. A quasi-experimental difference-in-difference approach will be used, comparing eligible households with two control groups: host communities of other energy infrastructure and ineligible households within eligible communities. This allows for isolation of the BDS's specific impact, especially when combined with the Community Funds guidance (CFs), a parallel intervention.

138. Theory-based methods will also be used to assess the causal pathways between the scheme and wider impacts including reducing risk of legal challenges and accelerating deployment.

139. Whilst we are not proposing a full value for money evaluation, under evaluation objective 4 we will be evaluating the effectiveness and efficiency of scheme design.

140. **Case Studies:** The evaluation programme will also identify and track the experiences of a handful of communities eligible for both the bill discount scheme and community funds over the course of the evaluation. This will provide evidence of the lived experience of communities, and a better understanding of interaction with the bill discount scheme, and evolving attitudes towards the new infrastructure.