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REACH COMMERCIAL MODEL AND COST-BENEFIT ANALYSIS

Report for Work Package B3

23 JUNE 2025

Contents

1 Introduction

The Rural Energy and Community Heat (REACH) project is assessing the applicability of a 'modular energy centre' (MEC)[1] and coordinated control of heat pumps in a rural community to the challenges faced by electricity distribution networks in ensuring that networks are able to accommodate the uptake of low carbon technologies (LCTs) and distributed energy resources (DER) as the UK transitions towards net zero.

As part of the Alpha phase of this Strategic Innovation Fund (SIF) project, Frontier Economics has been commissioned to undertake a cost-benefit analysis (CBA) of the REACH intervention using the SIF CBA framework, to identify and evaluate ownership and commercial models for the REACH intervention, and to illustrate the financial flows arising under these models.

This report documents the methodology and findings of this work package (WPB3) and constitutes the deliverable for milestone WPB3 M1. An accompanying Excel model (deliverable for milestone WPB3 M2) provides a populated version of the SIF CBA template.

The remainder of this reported is structured as follows:

- Section 2 describes the REACH intervention and the counterfactual that would arise if the REACH intervention was not implemented.
- Section 3 sets out the methodology and results for the cost-benefit analysis (CBA) which compares the social value of the REACH intervention against the counterfactual.
- Section 4 describes and evaluates the potential commercial and ownership models for the REACH intervention.
- Section 5 describes the financial flows arising under commercial and ownership models for the REACH intervention.
- Section 6 provides overall conclusions and suggests next steps which might be undertaken to resolve remaining uncertainties over the value of the REACH intervention.

[1] Comprising of generation and battery energy storage solution (BESS) technology.

2 Intervention and counterfactual

In this section we describe the issue to be addressed by REACH intervention and the counterfactual that would arise if the REACH intervention was not implemented. The counterfactual is important as it defines the types of benefits which the CBA accounts for (the CBA methodology and results are set out in section 3.) We then describe the REACH intervention in more detail, and the implications of installing the technology.

2.1 Issue addressed and the counterfactual

2.1.1 Issue

Uptake of low carbon technologies (LCTs), such as heat pumps and electric vehicles (EVs), by households and small businesses is increasing the level of peak and overall demand on electricity distribution networks. Connection of distributed energy resources (DER), such as solar PV, is increasing local supply of electricity at times that do not match with peak demand. LCTs and DERs can also cause voltage fluctuations due to the variable and intermittent nature of energy demand and generation patterns. Without intervention, this can lead to network constraints.[2] Distribution network operators (DNOs) are investing in network reinforcement (as well as flexibility services) to mitigate constraints and ensure that customers can connect and install technologies without these causing adverse impacts on the network.

DNOs have comprehensive programmes for planning and delivering reinforcement, to an n-1 standard[3], in response to forecasted network needs. However, there remains a risk that on some parts of the network uptake of LCTs and DER may occur faster than anticipated and that constraints materialise earlier than planned reinforcement works. Material impacts can arise from such network overloading including voltage drops and power quality issues, risk of asset (transformer) failure, and associated impacts such as customer outages, asset repair and replacement, safety, and environmental impacts. DNOs face a trade-off when planning reinforcement as the risk of network overloading decreases with the speed (and therefore cost) of reinforcement. Reinforcement is planned to optimise this trade-off but DNOs do not have perfect foresight of uptake of LCTs and DER.

The REACH intervention (described below) provides a solution which can be rapidly deployed as a temporary solution to mitigate network constraints.[4] The specific situation considered in

[2] Overloading can lead to different types of network constraints. Voltage constraints are limits on the voltage range on a point of the network, where dropping below or exceeding this range can disrupt power quality and potentially damage equipment. Overloading can lead to voltage drop. Thermal constraints are limits on the amount of power that can flow through a network asset (such as a transformer) without causing it to overheat, which can lead to asset failure.

[3] A standard where the network can continue to maintain normal operations when a single contingency event occurs (e.g. unplanned loss of transmission line, generator or transformer). This standard applies to the 11kV network, on which this project focuses.

[4] Deliverables produced under other Alpha phase workstreams provide further detail on the design of the intervention, specifically WP B1 on Energy Centre Design and WP B2 on Heat Solution.

this analysis is a rural 11kV feeder which is currently near its headroom, and where a significant amount of extra demand is added to the system unexpectedly. This means that, in the absence of some intervention, on peak winter days the 11kV feeder would be operating beyond its headroom.[5] Analysis undertaken as part of other REACH Alpha phase work packages indicates that this could lead to a voltage constraint on the 11kV network for specific communities. It is also possible that overloading could lead to a thermal constraint and overloading on the 11kV/33kV primary transformer, although this has not been found for the communities assessed at Alpha phase. In the counterfactual we assume that the network reinforcement cannot be brought forward in enough time to mitigate the constraint, that the REACH intervention is not deployed, and that alternative sources of flexibility (e.g. through DSO markets) are not available. Consequently, there is a risk that the above impacts materialise in the short term before planned network reinforcement is undertaken.

2.1.2 Other potential counterfactuals

Network overloading (as described above) is inevitable where the DNO cannot use other means to alleviate capacity constraints. We considered three other potential options but did not deem these to be the most plausible counterfactuals.

- **Increased speed of network reinforcement**. NGED have informed us that lead times mean that network reinforcement generally cannot be sped up with short notice. As noted above, significant spending would be required to increase reinforcement across the network without an indication of which areas need reinforcement. While there may be some scope to reprioritise the programme of reinforcement work, it is not certain that reprioritisation will allow for reinforcement to be sufficiently expediated (from the point in time that an unexpected increase in demand is detected) to alleviate the issues described above.
- **Increased use of available flexibility services** (e.g. through DSO markets). Sufficient flexibility is less likely to be secured quicky in the rural regions. The REACH intervention would be deployed only in areas where flexibility cannot be secured, providing a last 'line of defence'.
- **Delayed LCT uptake.** Under current regulations DNOs are generally not able to prevent households from installing smaller LCTs under 60A (e.g. heat pumps, private EV chargers, small-scale solar), except in specific circumstances where an upgraded connection is required – this is known as the 'connect and notify approach'.[6,7] Whilst the DNO can restrict large LCT connections (e.g. public EV chargers), the intervention is

5 This could occur for example if a number of oil or gas fired boilers in a community were upgraded to heat pumps over a summer without the DNO being notified.

6 There are some exceptions to this such as if the installation will exceed the property's Maximum Demand or if the property is connected to a looped supply. In these cases an upgraded connection will be required before the LCT can be installed.

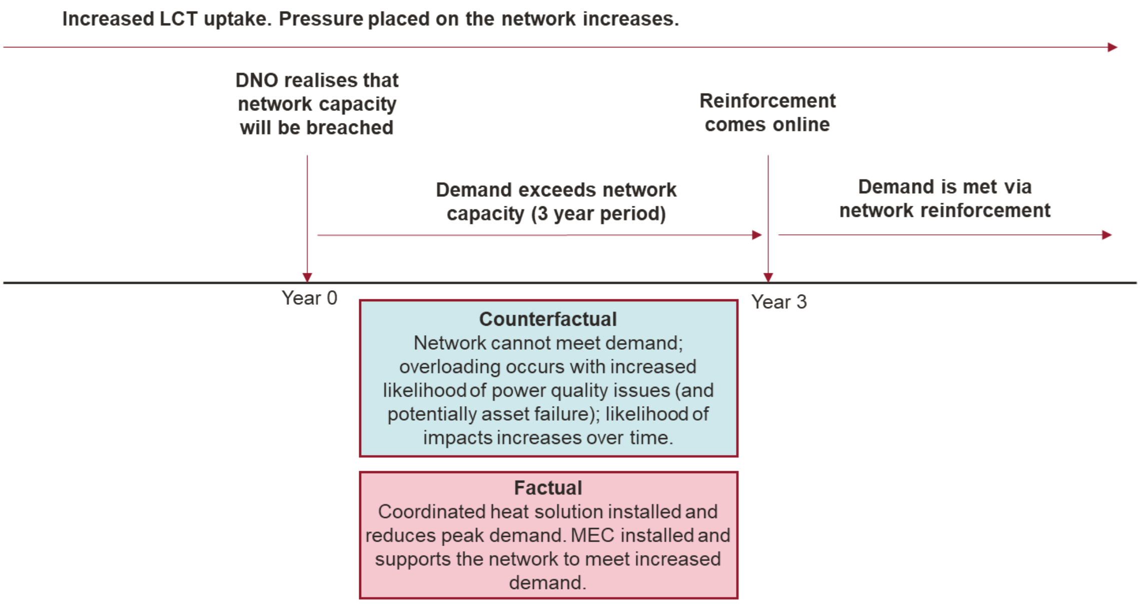
7 It may be the case that regulatory changes allow the DNO to prevent these connections in the future. We assume such change does not occur.

unlikely to allow for more of these connections before the issues described above would arise.[8] Regulatory change would be needed if it were ever deemed necessary to repeal the 'connect and notify' approach and allow the DNO to limit smaller LCT uptake. While this scenario could arise in future, for the purposes of this analysis we assume no regulatory change. If there was regulatory change benefits would still arise under the intervention, however the nature of these benefits would be different (i.e. the benefit would be faster LCT uptake, rather than avoided impacts from network overloading). Consequently, for the purposes of this analysis we do not model any benefits from faster LCT uptake, in order to avoid double counting of benefits.

2.2 REACH intervention

The REACH intervention is a solution which can be deployed to address the issue outlined above. It involves the introduction of two inter-linked technologies: the VEPod modular energy centre (MEC) and the Passiv coordinated heat solution. For the purposes of this analysis we assume that NGED receives sufficient prior notice of the risk of network overloading to deploy the intervention in the time needed to alleviate the network overloading issues described in the counterfactual above. We assume that the MEC is deployed for 3 years, after which the network is reinforced – i.e. there is a 3 year lead time for network reinforcement from when the risk of network loading is identified. This timeline is illustrated below.

Figure 1 Illustrative timeline of REACH intervention and counterfactual



8 The MEC is not sized large enough to allow such connections.

2.2.1 Technologies

The technologies are expected to be installed in rural locations. Two locations[9] have been shortlisted during Alpha phase for detailed feasibility assessments, however the intention is that the intervention can be deployed more widely across NGED’s network and across GB.

The MEC is installed in a community and connected to the 11kV network. It is a generation and storage asset which can provide a flexibility service to the network – i.e. charging when there is excess supply and exporting during peak demand periods. The deployment of the MEC is expected to be led and owned by NGED, or potentially by the community or other third party (we outline and evaluate potential ownership and commercial models in section 4). It is anticipated that the MEC will be deployed at suitable sites located within the local community (rather than DNO-owned sites) such as land adjacent to community infrastructure such as village halls or unused land, which the DNO or third party may need to purchase or lease. However in theory the MEC could also be installed on land owned by the DNO. For the purposes of this analysis we assume that a site and community support for the MEC has been secured.

The following components are part of the MEC:

- A generation module (genset) which can generate electricity and export to the grid. Generation is powered using hydrogenated vegetable oil (HVO);
- a battery energy storage system (BESS) which can charge from the generation module or the grid; and
- additional modules to allow the DNO to control the technology, including an MEC control module, a switchgear module and network monitoring equipment.

The MEC is designed to be moveable, and it is expected to be installed in a location on a temporary basis (approximately 3 years). Following this, and after the network is reinforced, the MEC can be moved to another site (unless it has reached the end of its asset life). The MEC has an asset life of around 15 years (depending on battery usage), meaning that the asset can be deployed up to around 5 times. When the MEC is removed/relocated certain ‘residual assets’ can be retained on site – the concrete slab that the MEC would be situated on and network connection infrastructure (11kV switchgear). The local community could use these residual assets to connect a community owned asset, such as EV charge points, a BESS, or renewable generation.[10] The REACH project is developing an Options Assessment Tool that can be used to determine the appropriate assets to deploy. If the connection is not required after the MEC is removed, the assets can be removed and the site restored to its original condition.

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9 The chosen locations are Awel Aman Tawe in Wales and Bigbury Net Zero in England.

10 While the REACH project aims to facilitate the deployment of community-owned assets, this could potentially be another third-party (non-DNO) entity.

The Passiv heat solution is rolled out to the community via the installation of smart thermostats (Passiv Smart Thermostats, PSTs) to new heat pumps. There is a potential for existing heat pumps to be retrofitted with the smart thermostats.

On its own, the Passiv heat solution enables demand side response which allows customers to benefit from participating in a broad range of flexibility services. After the MEC is removed from the community, the Passiv heat solution will remain in place and can continue to provide these benefits.

Deploying the technologies *together* results in a lower capacity requirement for the MEC to address overloading on the 11kV network, potentially reducing the cost of installing the MEC.[11] It additionally reduces costs to the grid by providing a forward look on heat pump load in the community, enabling the MEC to optimise generation, charging and discharging.

For the purpose of our CBA, we have considered two alternative counterfactuals:

- One where widespread deployment of the Passiv heat solution in the community would not occur in the counterfactual (and so all its benefits can be attributed to REACH); and
- one where it is assumed that the Passiv heat solution *is* already deployed in the community, and so only the benefits that it unlocks from the MEC (rather than the broader set of benefits from greater heat flexibility) are attributed to REACH.

2.2.2 Implications for benefits

Compared to the counterfactual, the REACH intervention leads to the following key benefits:

- **Reduced power quality issues and risk of asset failure** that may otherwise arise in the counterfactual. When the network is operating above its headroom this overloading may lead to a voltage constraint (voltage drop) which can cause power quality issues for customers. Additionally, if a thermal constraint were to arise at either the primary or secondary substation level this can increase the risk of transformer failure which can cause customer outages, damage to assets (requiring repair or replacement), safety risks, and environmental damage.
- **Reduced electrical losses.** The MEC generates electricity which is consumed locally, reducing losses that would occur when electricity is transported a longer distance. The battery will typically charge from the grid at times of low demand (e.g. overnight) when losses are lower and discharge for local consumption at peak times, thereby displacing electricity that would otherwise be transported at peak times (when losses are higher).[12]

[11] However, as is illustrated through the CBA in Section 3, the MEC can also deliver benefits through participation in broader energy markets (in addition to addressing the local network need). A different and potentially larger sizing configuration may increase the net benefits delivered by the MEC if it is able to participate in these markets.

[12] Distribution losses are lower when electricity demand and the amount of current flowing through the network is lower, leading to less heat generation and fewer losses. Consequently Line Loss Factors (LLFs), which are multipliers used to account for losses on the distribution network, vary between day and night. We adapt the methodology and tool

- **Reduced emissions**. The MEC generates electricity using HVO, which displaces electricity from the grid at peak demand times where grid emissions may be higher. The battery will charge from the grid at peak supply times (when carbon intensity is low) and displace higher carbon generation at peak demand times. This benefit will be small in the longer-term as low carbon generation increasingly becomes the marginal source of electricity on the wholesale market.

After the removal/relocation of the MEC, the REACH intervention provides the option for the local community to install their own assets at the site:

- In the case where the community decides to introduce community owned assets, the intervention may result in faster and cheaper introduction of these assets. The scale of this benefit will vary depending on what the community opts to install at the site.
- In the case where the community does not want to introduce community owned assets, costs are associated with the removal of residual assets (e.g. removal of concrete slab and site remediation).

The full set of impacts (costs and benefits) associated with the REACH intervention is outlined in section 3, along with the methodology for quantifying them (where relevant) and the results of the CBA.

developed by the ENA Technical Losses Working Group for estimating the impact of flexibility interventions on losses – we detail this further in section 3. See: https://www.energynetworks.org/publications/enic-2019-ena-technical-losses-working-group

3 Cost benefit analysis

In this section we outline the general assumptions and methodology underpinning the CBA (3.1) and the results of the analysis (3.2).

3.1 Methodology

As far as possible the analysis is based on the Ofgem SIF CBA Guidance and the Ofgem SIF CBA Template, which are closely related to the standard approach required for any DNO CBA as part of RIIO-ED2.

The CBA compares the social value of the REACH intervention against a relevant counterfactual, as described in section 2. The exact locations on NGED's network where the REACH intervention would be deployed if the project proceeds to Beta stage (or more broadly across the network beyond Beta stage) have not yet been identified. However, two communities have been shortlisted during Alpha stage for detailed feasibility assessments: Awel Aman Tawe (AAT) in Wales and Bigbury Net Zero (BNZ) in England. We therefore use these two locations as representative communities for the CBA, and draw on the data and analysis which has been produced as part of other Alpha phase work packages.

The CBA focuses on assessing the benefits from the MEC when it is deployed as a temporary solution to address a constraint arising from network overloading. We assume the MEC is redeployed when reinforcement is undertaken, and can be redeployed until it reaches the end of its asset life. We do not evaluate the costs/benefits arising from any assets that may be installed by the community after the MEC is removed. As well as there being a range of different assets that could be installed by the community, with vastly different cost and benefit impacts, there is no guarantee that the community would install assets, nor that they would not have done so without the MEC previously being installed.

We assume that the community does not use the site/connection following the removal/redeployment of the MEC and therefore the DNO incurs the costs of site remediation. This represents a conservative approach because it is likely that some communities will use the site/connection and so the full remediation costs are not borne. In addition, communities using the site/connection will likely only do so if it there is a positive private cost-benefit analysis. Assuming no significant negative externalities, incorporating these positive cost-benefit analyses into our findings would push the results in a more positive direction.

3.1.1 Use of the technologies

Many of the costs and benefits associated with the REACH intervention are related to how the two technologies are expected to operate. We therefore define the how the MEC and the heat solution will be used, drawing on data and analysis produced as part of other Alpha phase work packages.

MEC

Peak demand usage

To size the MEC battery and genset in the chosen communities, VEPod calculated half-hourly usage of the MEC (in response to network overloading) on a peak winter demand day in 2030. This analysis found no use for the MEC under normal operation of the network, with it only being required during abnormal operation (i.e. when the network is operating under n-1 conditions). However, NGED expects the MEC will only be deployed in communities where it is needed in an ‘intact’ network condition (i.e. when the network is not operating under n-1 conditions, with no damage or outages). If the REACH project proceeds to Beta phase, it will seek to identify such communities.

Therefore, to calculate a CBA that is representative of how the MEC will be deployed, we assume that use of the MEC during abnormal operation as modelled by VEPod occurs in an intact site. The modelling provides illustrative cost-benefit calculations for the case where an MEC is deployed in communities where it is needed in an intact network condition.

VEPod’s modelling includes MEC usage under ‘coordinated’ and ‘uncoordinated’ heat pump usage. As the coordinated heat pump solution (Passiv) is expected to be deployed alongside the MEC, we use the ‘coordinated’ heat pump usage.

Annual usage

Quantifying costs and benefits associated with the REACH intervention requires data on annual use of the MEC. Forecasting half-hourly network load profiles for the period over which the MEC is deployed in each community was not within scope of this project.

Therefore, we take 2024 half-hourly load profile data[13] for a 11kV feeder from each community. We use this to extrapolate the half-hourly profile for the peak winter day in the years in which the MEC is assumed to be deployed (discussed below).[14]

As existing heating systems (primarily electric resistive and off-grid oil and gas) are replaced with heat pumps, the load profile will change. Our high level CBA presented does not use electricity prices or marginal emissions which vary from half-hour to half-hour, which will reduce the impact of assumptions regarding the load profile. However, if more detailed assessment were to be undertaken in future, the sensitivity of the results to the assumed load profile should be tested.

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13 Expressed in current (amps).

14 For AAT, the MEC is expected to be deployed in 2029 to 2031. Data on peak winter demand is not available for 2031. We therefore assume the percentage growth in peak winter demand in 2030 to 2031 is equal to the growth in 2029 to 2030.

Battery and genset usage

We assume that the battery is used in the first instance. Project partners have confirmed that the genset would only be used where the battery is not able to import enough charge from the grid in order to meet export needs.

Use of the MEC at times when it is not needed to deal with network demand

Annual modelling suggests that for a large proportion of the year, the MEC is not needed to address overloading on the 11kV feeder. In addition to meeting the need on the 11kV feeder, the MEC could be used to provide services in other energy markets, such as NESO markets, upstream DSO flexibility markets, or trading in the wholesale electricity market. However, this is unlikely to be feasible under a DNO ownership model – we expand on this further in section 4.

Detailed modelling of participation in wholesale or other energy markets is out of scope of this project. However, to illustrate the potential benefits that could arise should the MEC be able to participate in energy markets we undertake high level analysis of battery participation in the wholesale market assuming one charge/discharge cycle a day, on days where the MEC is not required to address overloading on the 11kV feeder. We include this as a sensitivity in the model.

Passiv heat solution

In line with other Alpha phase work packages, we calculate heat pump uptake assuming that it is one year ahead of DFES 2024 forecasts.[15]

To evaluate the benefits of PST participation in the flexibility market we assume that all households with heat pumps (existing or new) take up the Passiv heat solution[16] and use the PST to participate in flexibility markets. We model the benefits over the length of the Passiv heat solution's asset life. We do not model the benefits for households who take up a heat pump after the MEC has been removed. Annex A sets out the uptake of PST across the communities.

However, we also consider a scenario where households participation in flexibility markets is the same in the counterfactual (i.e. there are no additional flexibility benefits under the intervention). This is because households with heat pumps could also install smart thermostats and participate in flexibility markets in the absence of the MEC and the coordinated heat solution.

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15 This is because the MEC will be deployed in rural communities where LCT uptake has outstripped DFES forecasts. Data is only available 5-yearly from 2040 to 2050 and so we use a linear interpolation between these years. Heat pump uptake is assumed to remain constant after 2049.

16 This assumption aligns with Passiv modelling for the Alpha phase.

3.1.2 Costs and benefits

The SIF CBA guidance categorises three broad impacts:

- **Investment or avoided costs**: Principally capital and operating expenditure (capex and opex) and any costs for replacing assets due to failure.
- **Environmental net benefits**: Any costs or benefits associated with changes of emissions.
- **Social net benefits impacts**: Any social costs of failure (customer minutes lost, incidence of injury) or social benefits (due to cleaner air, reduced noise, and visual amenity).

The rest of this sub-section sets out the methodology for the modelled costs and benefits in each category.

Financial net benefits

Capex and opex costs

Capex costs of the MEC are provided by VEPod. They are based on sizing an MEC for peak demand in 2030 for the two communities. In BNZ, the battery is 2MWh with a 0.5MW inverter and a 833kW genset. In AAT, the battery is 0.72MWh with a 0.28MW inverter and a 226kW genset. Capex costs include the upfront cost of building the MEC,[17] the cost of relocation, and the cost of site remediation. In particular, the upfront cost does not include grid connection or land purchase.

Opex costs of the MEC relate to:

- HVO fuel costs. The £/kWh cost was provided by VEPod and applied to the annual kWh of HVO calculated in the annual modelling. No other opex costs are included for the genset.
- Battery costs, based on Mott MacDonald storage cost technical assumptions (lithium ion battery) developed for the UK Department for Energy Security and Net Zero (DESNZ).[18]

Capex costs of installing a PST are assumed to be equal to the counterfactual cost of a standard smart thermostat. We assume that households with an existing heat pump who decide to install a PST already have a standard smart thermostat which must be replaced when the MEC is deployed. We use the cost of a one-zone PST provided by Passiv.

Specific cost assumptions are shown in Table 1.

[17] Upfront costs include all equipment related to the genset and battery (e.g. generator, lithium ion battery racks), container fabrication, switchboard gear, factory integration and site delivery.

[18] See: https://assets.publishing.service.gov.uk/media/5f3cf6c9d3bf7f1b0fa7a165/storage-costs-technical-assumptions-2018.pdf. Opex costs include annual costs related to operation, inspection, maintenance, replenishment/refurbishment of consumables, insurance and security.

Table 1 Inputs for CBA

Assumption	BNZ	AAT	Source
MEC upfront cost (£)	850,412	582,867	VEPod
Site remediation costs (£)	7,116	7,116	VEPod
Relocation costs* (£)	86,940	72,607	VEPod
Battery opex costs – low (£/kW/year)	17.88	17.88	DESNZ (Mott MacDonald) (lithium ion battery 1MW, 2.5MWh)**
HVO costs (£/litre)	1.43	1.43	VEPod
Passiv capex costs (£/installation)***	220	220	Passiv

Source: Frontier Economics, based on various sources as listed

*Note: Prices in FY 2023-24 price year. * Assumes costs of new site, crane hire plus 150 miles for transport. ** We use the midpoint of the 'low' 2020 and 2030 costs given reductions in battery costs since DESNZ assumptions were published in 2018.*[19] ****Assumes a 1-zone PST.*

Financial benefit from reduced risk of asset failure

The intervention has the potential to reduce the probability of failure of two types of network assets, by reducing the risk of thermal overloading leading to transformer failure.

- **Secondary substation (6.6/11kV transformers):** The Passiv heat solution reduces peak demand by coordinating heat pump usage by households connected to the network below the secondary substation level. This helps to reduce risk of thermal overloading leading to failure of secondary transformers.
- **Primary substation (11/33kV transformers):** In addition, it is plausible that in some circumstances the presence of the MEC, by reducing peak demand on the 11kV feeder, may help to reduce risk of thermal overloading leading to failure of 11/33kV transformers. We include reduced risk of failure at the primary substation level as a sensitivity only.[20]

We value the modelled the reduced probability of failure by multiplying the following values:

- **Number of assets affected**: We assume that five 6.6/11kV and two 11/33kV transformers are affected by each MEC installed, based on NGED's view of the typical

[19] For example see: https://about.bnef.com/insights/commodities/lithium-ion-battery-pack-prices-see-largest-drop-since-2017-falling-to-115-per-kilowatt-hour-bloombergnef/

[20] Analysis undertaken as part of other Alpha work packages has only identified a voltage constraint arising on the 11kV feeder. We therefore include reduced risk of 11kV/33kV transformer failure (arising as the result of a thermal constraint) as a sensitivity only.

number of transformers located in each community at the primary and secondary substation levels.

- **Baseline probability of failure**: We assume that 6.6/11kV and 11/33kV transformers have asset lives of 50 years.[21] We apply an illustrative baseline probability of failure equal to 1 in 50 (2%) per year.
- **Assumed increase in probability of failure without the MEC:** We apply an illustrative assumption that failing to introduce the MEC will double the probability of failure.
- **Financial cost of failure:** Based on the Common Network Asset Indices Methodology (CNAIM) (£11,081 for the 6.6/11kV transformer and £104,527 for the 33kV transformer).[22]

This approach is illustrative and serves to demonstrate the potential reduction in cost of failure in the intervention compared to the counterfactual. Further work would be needed to understand the true impact of network overloading on the probability of failure.

Environmental net benefits

Environmental benefit from reduced risk of asset failure

We split the benefits related to reduced risk of asset failure into their separate components in line with SIF guidance to report financial, environmental and social net benefits separately.

We use the same approach as outlined above to calculate the Financial benefit from reduced risk of failure. We apply the reference environmental cost of failure from the CNAIM (£4,540 for the 6.6/11kV transformer and £20,320 for the 33kV transformer).

Reduced electricity losses

Losses are the difference between the electricity entering the network and leaving the network at meter points. Technical losses relate to the physics of the passage of current through cables and transformers – and can vary based on voltage level and network load – while non-technical losses include theft and measurement errors. We focus on assessing the impacts of technical losses arising from reducing or shifting grid electricity generation, as the REACH intervention is not expected to have an impact on non-technical losses.

Operation of the MEC genset will reduce the amount of electricity lost as it flows through the network, as electricity is generated closer to its point of consumption. Operation of the MEC battery will also reduce electricity losses by shifting the time at which electricity is imported (from the wider grid) for local consumption at a later point in time – as distribution losses are

21 Illustrative assumption agreed with NGED.

22 The CNAIM was developed by the DNOs in response to RIIO-EQ1 requirements for DNOs to report information relating to Asset Health and Criticality, and updated for RIIO-ED2. It allows calculation of asset health and probability of failure and asset criticality and costs of failure. The costs of failure are split into financial, environmental, safety and network performance and reported in 2020/21 prices (converted to 2023/34 prices for this analysis). See: https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/dno_common_network_asset_indices_methodology_v2.1_final_01-04-2021.pdf

lower when electricity demand and the amount of current flowing through the network is lower leading to less heat generation and fewer losses (typically at times when the battery is expected to be charging) – although such reductions are smaller than those associated with local generation, and as described below the use of the battery will also increase losses.

Technical engineering evaluation of losses was out of scope of this project. We therefore use Line Loss Factors (LLFs) to undertake simplified losses calculations, adapting an approach and tool developed by Energy Networks Association (ENA) Technical Losses Working Group for estimating the impact flexibility interventions on losses.[23] The ENA tool uses generic loss factor data for each DNO – more specifically, generic demand and generation LLFs by metered voltage levels (132kV, EHV, HV, LV in GB) and relevant time periods (peak, winter, night, other) – that represent average network losses associated with demand and generation across a DNO licence area.

We use the LLFs from the ENA tool for NGED's South West licence area.[24] We combine these with use of the genset and battery calculated in the annual modelling. This is likely to underestimate the volume of losses, as it does not account for losses that occur on the transmission network. However, the volume of losses on the transmission network is much lower than on the distribution network accounting for around 2% of electricity transmitted, versus up to around 8% on the distribution network.[25] Benefits from reduced electricity losses are also a small part of the overall CBA.

The SIF template calculates two benefits from reduced losses. First, it calculates the direct value of reducing lost electricity by multiplying the size of losses by the value of such losses (£74.42/MWh). Second, it calculates the emissions savings associated with reduced electricity losses using an emissions factor (which falls from 0.193t/MWh in 2025 to 0.001t/MWh in 2050). These emissions are valued using carbon prices, in line with other emission benefits in the SIF template (which rises from £292/tCO2e in 2025 to £426/tCO2e in 2050).

Increased electricity losses

In contrast, there is an *increase* in electricity losses because the battery is inevitably not 100% efficient. We calculate the lost electricity based on modelled battery discharge and the assumed 10% round-trip inefficiency. We value the benefit using the SIF CBA template's assumed £/MWh value of electricity losses.

We do not include emissions associated with such electricity losses because the battery is generally assumed to charge during low demand periods (such as the night) when the marginal generator is likely to be a lower cost, renewable generator. While this is a simplifying

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23 See https://www.energynetworks.org/publications/enic-2019-ena-technical-losses-working-group

24 We note that AAT is located in South Wales (not the South West license area). However, differences in LLFs between licence areas are small, and as electricity losses only make up a small amount of the overall CBA results using the South Wales LLFs would not have a material impact on the CBA.

25 See https://bscdocs.elexon.co.uk/guidance-notes/transmission-losses and https://www.neso.energy/document/144711/download

assumption, the increased importance of intermittent renewables on the system means that there will likely be more periods of zero or even negative prices in future, during which the battery could be charged. However, any more detailed future assessments of the intervention should consider assessing the impact of half-hourly load, price and emissions profiles.

Reduced emissions from renewable generation and storage

Both the battery and the genset can lead to emissions savings. The battery charges from the grid at low demand times, when emissions are low or zero, and exports to the grid at peak times, when emissions are high. HVO generates fewer emissions per kWh of electricity than average grid emissions (according to DESNZ GHG conversion factors).[26]

Such savings are not included here to avoid double counting. They are valued as part of the network benefit from reducing and shifting electricity grid generation (see below), where the wholesale prices used to value such benefits include the traded carbon price.

To avoid overestimating emission savings, we account for emissions generated by the use of HVO in the genset. We use the annual usage of the genset and HVO emissions from DESNZ GHG conversion factors (0.03558kgCO2e/litre).[27] The SIF template values these emissions using the DESNZ carbon values for appraisal.

Emission savings are likely underestimated using this approach because the genset will run at peak times. Marginal grid emissions are likely to be higher at such times than the emissions reflected in the wholesale prices used to value the avoided benefits from reducing electricity generation costs. The wholesale prices also include a traded carbon price rather than a social cost of carbon (which is reflected in the DESNZ carbon values) further increasing the likelihood of underestimation.

Social net benefits

Safety benefit from reduced risk of failure

We use the same approach as outlined above to calculate the financial benefit from reduced risk of failure. We apply the reference safety cost of failure from the CNAIM (£5,749 for the 6.6/11kV transformer and £28,012 for the 33kV transformer).[28]

26 See https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2023

27 Converted to 0.008kgCO2e/kWh using litre per kWh HVO usage provided by VEPod.

28 We note that a lower discount rate (1.5%) should be applied to the safety benefit. Due to the constraints within the structure of the SIF template where the standard discount rate is applied to bespoke cost and benefit inputs, it has not been possible to apply this discount rate. This is unlikely to have a meaningful impact on the results as the safety cost of failure makes up only a small proportion of total benefits.

Network performance benefit from reduced risk of failure

We use the same approach as outlined above to calculate the financial benefit from reduced risk of failure. We apply the reference network performance cost of failure from the CNAIM (£5,176 for the 6.6/11kV transformer and £45,876 for the 33kV transformer).

Reductions in the periods when network voltage drops occur

Analysis undertaken as part of other Alpha work packages has identified a voltage constraint arising due to overloading on the 11kV feeder. When the network is operating above its headroom, overloading leads to a voltage drop which can cause power quality issues for customers.

We value the reduced implications for network voltage by multiplying the following values:

- **Number of customers connected:** We assume that 1000 customers would experience a reduction in voltage without the MEC.[29]
- **Costs of reducing in voltage:** Low voltage can cause real issues for consumers.[30] In the absence of a standardised way to treat these issues, we used Ofgem's Guaranteed Standard of Performance as a proxy for the harm caused per customer.[31] Under this guidance, DNOs are fined £30 if they fail to investigate low voltage quickly enough following complaints. We apply this figure once per year the MEC is deployed, for each customer connected.

Since there is no standard way of putting a social value on low voltages, we have carried out a cross-check of our assumed value using the value of lost load (VoLL). Based on our MEC modelling, we calculate total demand during periods when demand exceeds the feeder load. Such demand is expected to experience a voltage drop. Then, we consider the value if all of this load was lost using the SIF CBA template value of lost load (£2.87/kWh). We convert this to a per customer value continuing the illustrative assumption that 1000 customers would experience this loss of load. Finally, we compare our assumed £30 value with the value of lost load:

- In BNZ, the per customer VoLL is £2,900-£4,300. Therefore, our assumed cost of reduced voltage is around 1% of the inconvenience of lost load.
- In AAT, the per customer VoLL is £230-£350. Therefore, our assumed cost of reduced voltage is 10% of lost load.

29 Illustrative figure provided by NGED.

30 For example, lighting may be dim or flicker, or heating and cooking appliances may take longer to reach the desired temperature.

31 The Guaranteed Standards scheme provides payments to companies if the DNO fails to meet the standards set out in this document. See: https://www.energynetworks.org/assets/images/Resource%20library/DNO%20NOR%202023.pdf

We would expect that the monetary value to consumers of low voltages would be well below losing supply altogether. The value we are using, while illustrative, is consistent with this.

System benefits from reducing and shifting grid electricity generation as a result of the MEC

The operating profile of the MEC results in avoided grid electricity generation costs due to the reduction of grid electricity generation.

- Reducing grid electricity generation (as a result of the genset): When the MEC genset exports electricity, this displaces grid electricity generation. We account for this avoided electricity generation cost by multiplying the quantity (MWh) of genset export by an electricity price based on DESNZ energy and emissions projections[32] ('Reference' scenario).[33,34]
- Shifting grid electricity generation (as a result of battery usage): The MEC charges at times of low demand and exports at times of peak demand. This is expected to shift consumption from periods where the marginal cost of electricity generation is high to periods where the marginal cost of electricity generation is low. We account for this by multiplying battery discharge with revenue from flexibility savings per MWh of energy discharged in 2022 (£149) according to Cornwall Insight (2024).[35]

Both figures account for the avoided carbon costs of electricity generation which are embedded in the wholesale electricity price.

Potential additional system benefits from shifting grid electricity generation as a result of the MEC

As outlined in section 3.1.1, in addition to meeting the need on the 11kV feeder, the MEC could be used to provide services in other energy markets, such as NESO markets, upstream DSO flexibility markets, or trading in the wholesale electricity market. This is unlikely to be feasible under a DNO ownership model, as we outline in section 4, but may be possible for other ownership models. Therefore, as a sensitivity, we include illustrative assessment of the scale of the potential benefits that could be realised.

We undertake high level analysis of battery participation in the wholesale market assuming one charge/discharge cycle a day, on days where the MEC is not required to address overloading on the 11kV feeder. The model includes a sensitivity to flex the proportion of such

32 See Annex M here: https://www.gov.uk/government/publications/energy-and-emissions-projections-2023-to-2050

33 This likely underestimates the network benefits because the genset will likely displace electricity at peak times, when costs will be higher than average.

34 HVO is more expensive than average grid electricity. Therefore, using the genset rather than grid electricity results in a net cost. HVO costs are included in the MEC opex costs (set out in Capex and opex costs).

35 See https://www.cornwall-insight.com/thought-leadership/blog/revenue-stacking-for-flexibility-a-deep-dive-into-gb-electricity-flexibility-services/. The figure refers to the average service price of wholesale services, which they note is an underrepresentation of the values that flexible assets can achieve.

days where the MEC participates in the wholesale market; our reported figures assume it participates on all of these days.

In line with the approach above, we multiply the battery discharge by the revenue from flexibility savings per MWh in 2022 (£149).[36] according to Cornwall Insight.

Overall, this approach may overestimate the potential benefit arising from participation in the wholesale market, as it assumes the battery can cycle on a daily basis. However, it does not capture potential benefits from participation in other markets such as the balancing or capacity markets.

This figure additionally includes the carbon savings (and therefore environmental benefits) associated with such flexibility.

System benefits from shifting grid electricity use as a result of Passiv

Similarly, the Passiv heat solution optimises heat pump usage and allows customers to participate in flexibility services.[37] Passiv assumes that each customer will generate around £96 in revenue (including the cut taken by Passiv and other providers). We calculate the total benefit by multiplying this value with the number of customers using PST.

There are likely to be additional emissions reduction and electricity loss benefits associated with such flexibility. However, we have been unable to estimate these without forecast electricity (kWh) estimates of flexibility services provided by Passiv.

3.1.3 Deployment scenarios

Illustrative communities

We calculate the CBA for BNZ and AAT separately, as the profile of MEC usage on a peak day varies significantly across the communities. We assume that the MEC and Passiv heat solution are deployed together, in 2026 in BNZ and 2029 in AAT. These are the first years that there is demand for the MEC in at least one half-hour period according to VEPod's modelling of abnormal network conditions.

We assume the MEC is deployed in each community for three years before it is moved to another site, where the same benefits are seen for three years.

36 Cornwall Insight (2024) Revenue Stacking for Flexibility: A Report for NGED. Value updated to FY2023-24 prices. See: https://www.cornwall-insight.com/thought-leadership/blog/revenue-stacking-for-flexibility-a-deep-dive-into-gb-electricity-flexibility-services/

37 Households have been participating in NESO's Demand Flexibility Service via Passiv. See: https://www.passivuk.com/insight/demand-flexibility-service-using-passiv-smart-controls-to-support-the-national-grid-by-tom-latimer-passiv-algorithm-developer/

Wider rollout

We calculate a simple average CBA across the two communities. This is an illustrative CBA for the average REACH intervention.

We then follow SIF guidance to calculate benefits in two scenarios:

- **Deployment across the NGED network**: As part of Alpha phase, it has not been possible to determine the number of sites where an MEC could be deployed based on technical analysis. We use an illustrative assumption agreed with NGED that there could be 25 communities that could benefit from the REACH intervention (i.e. five MECs deployed across five communities, with the Passiv technology deployed in each).

- **Deployment across GB**: We scale up the number of sites the intervention would be deployed across the NGED network across all DNO networks using 2023/24 network length according to Ofgem.[38] We use network length, rather than customer numbers, because this reflects the fact that some DNOs (e.g. UKPN) are likely to have high customer numbers but only a small proportion located in rural areas.

3.1.4 Other inputs

Cost of capital

Capital expenditure (the upfront cost of the MEC) is capitalised and depreciated (using a straight line assumption). The SIF CBA default pre-tax WACC figure of 4% has been used as the cost of capital.

Asset life

Based on input from the project partners, we assume the practical asset lives of the asset (over which benefits are realised) are:

- 15 years for the MEC; and
- 10-15 years for the PST.

However, in the SIF template, where capital costs are assumed to be incurred by the DNO, costs are assumed to be capitalised into the RAB (and a WACC incurred) and then recovered over a standard 45 year regulatory asset life.

Appraisal period

The SIF CBA framework considers the period from 2024 to 2070. This is consistent with the guidance provided for the RIIO-ED2 CBA, Ofgem (2021), *RIIO-ED2 Cost Benefit Analysis (CBA) Guidance* which is designed to give clear visibility over any assets that are expected to

[38] See: https://www.ofgem.gov.uk/publications/riio-2-electricity-distribution-annual-report-2023-2024

have a 45 year life. Although the asset life of the MEC is only 15 years, it is assumed to be capitalised across the entire 45-year regularly asset life in line with SIF CBA guidance.[39]

Discount rate and price base year

The SIF CBA applies the standard social discount rate as set out in the Green Book: 3.5% for periods of up to thirty years, and 3.0% beyond this. A reduced discount rate is used for health-related costs and benefits, to remove the 'wealth effect' from the discounting. This reduced discount rate is 1.5% for periods of up to thirty years and 1.29% beyond this.

All prices are expressed in FY2023-24 terms in line with SIF guidance, with CPI-H used to convert prices where required.

3.1.5 Sensitivity analysis

Table 2 sets out the scenarios we test and present in the results section below. We test the following results for both BNZ and AAT and for wider deployment.

We vary across two key dimensions:

- Whether to include the benefits from household participation in flexibility markets through the PSTs. We consider scenarios where household participation in flexibility markets is the same in the counterfactual (i.e. there are no additional flexibility benefits under the intervention). This is because households with heat pumps could also install smart thermostats and participate in flexibility markets in the absence of the MEC and the coordinated heat solution.
- Whether the battery is used for wholesale market participation: In some scenarios, we assume that when the MEC is not needed for network control, the battery is used to generate revenue in wholesale market

Table 2 Scenarios analysed

#	Scenario	Battery used for wholesale market participation	Flexibility benefits from PST beyond counterfactual
1	MEC with no PST flexibility benefits	×	×
2	MEC with full PST flexibility benefits	×	✓

[39] SIF CBA guidance stipulates that longer term expenses (such as assets) should be capitalised and spread over 45 years. This aligns with treatment of capex under the RIIO regulatory framework where a depreciation policy based on a 45 year asset life is applied to capex in the regulated asset base (RAB).

#	Scenario	Battery used for wholesale market participation	Flexibility benefits from PST beyond counterfactual
3	Market participation with no PST flexibility benefits	✓	×
4	Market participation with full PST flexibility benefits	✓	✓

Source: Frontier Economics

The model additionally includes the flexibility for NGED to test alternative values over the following variables:

- Use of the MEC
  - Relocation of the MEC 5 times (Yes or No)
  - Including site remediation in costs (Yes or No)
  - Assuming battery component used year round to participate in wholesale markets (Yes or No) and the proportion of days where it is not needed for network constraints where it is used (%)
- Passiv users and benefits
  - Percent of new and existing heat pump users who take up Passiv (%)
  - Length of time over which benefits from Passiv occur (10 or 20 years)
- Probability of failure
  - Including the benefits for the 33kV risk of failure (Yes or No)
  - Probability increase in the risk of 11kV transformer failure in the counterfactual (%)
  - Probability increase in the risk of 33kV transformer failure in the counterfactual (%)
- Rollout of asset
  - Number of MECs deployed across NGED sites (number)
  - Whether the AAT and BNZ specifications are rolled out (Yes or No, for each)

3.2 Results

In this section, we present the results of the CBA across the scenarios set out above.

Two graphs are presented for each scenario and community. The first splits the total NPV into financial, social and environmental net benefits, based on the SIF definitions and as explained in 3.1.2. The second graph shows the NPV costs and benefits, split out into the following groups:

- **Benefits – Avoided thermal overloading:** Financial, environmental, safety and network performance benefit from reduced risk of failure
- **Benefits – Avoided voltage drop**: Reductions in the periods when network voltage is reduced
- **Benefits – Passiv shift of electricity generation**: System benefits from shifting electricity generation as a result of PSTs
- **Benefits – MEC shift/reduction of electricity generation**: System benefits from shifting and reducing electricity generation as a result of Passiv and associated emissions increase from HVO
- **Costs related to the MEC**: MEC capex and opex costs
- **Costs related to Passiv**: PST capex costs
- **Costs – Net electrical losses**: Net losses and associated emissions

3.2.1 Scenario 1 – MEC with no PST flexibility benefits

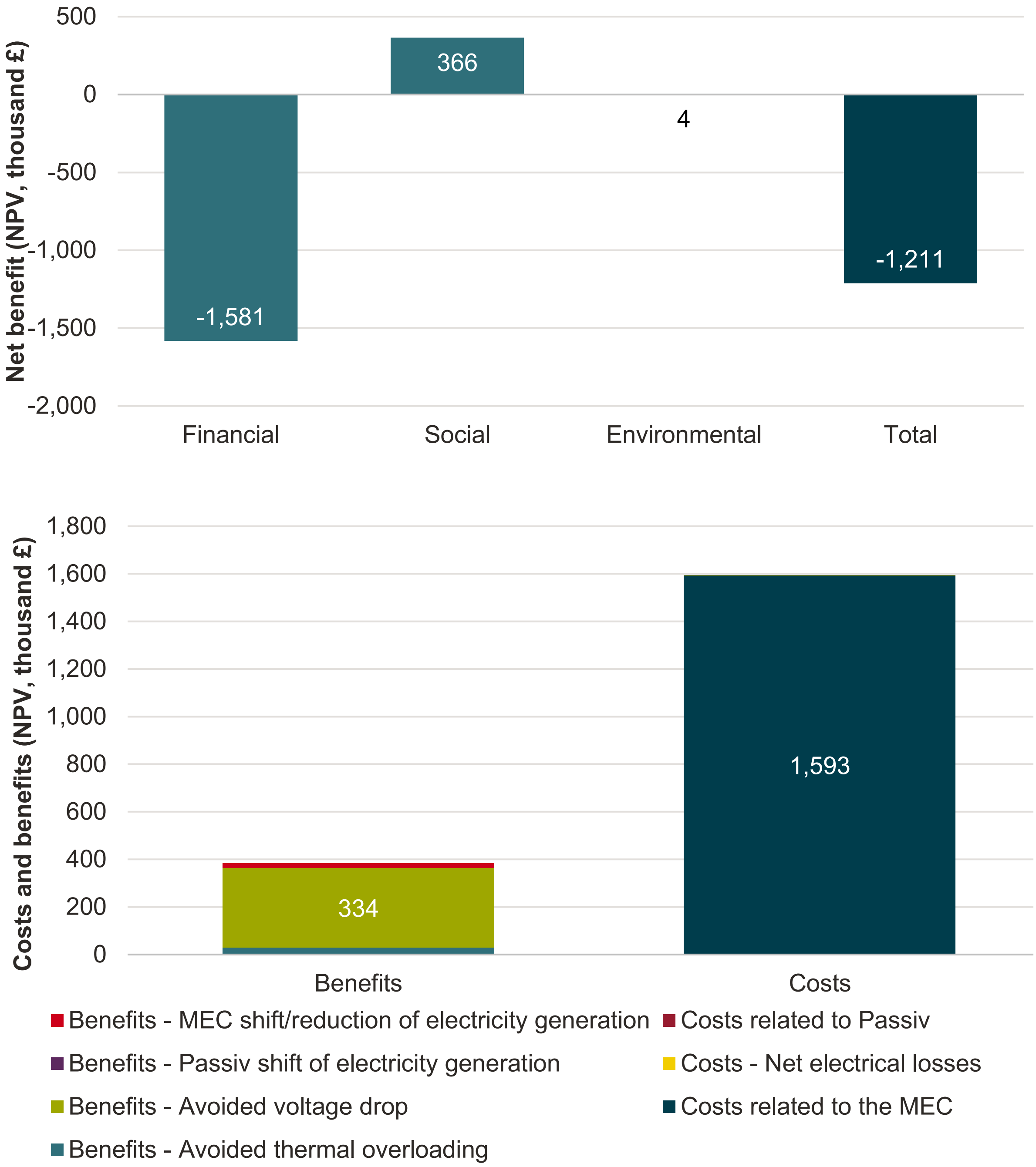
We assume the MEC is redeployed in five communities. We assume that household participation in flexibility markets (via heat pumps and smart thermostats) is the same as in the counterfactual so there are no additional benefits from flexibility services.

The CBA is negative in both communities: a net cost of **£1.2m** in BNZ (see Figure 2) and **£589k** in AAT (see Figure 3). The primary driver of benefits is the societal benefit of less voltage reduction compared to the counterfactual (around £300m in both communities). These benefits do not outweigh the significant capex costs.

In both communities, costs are larger than the net cost in a situation where the MEC is not redeployed. The additional societal and environmental benefits do not outweigh the increased cost of relocation and site remediation.[40]

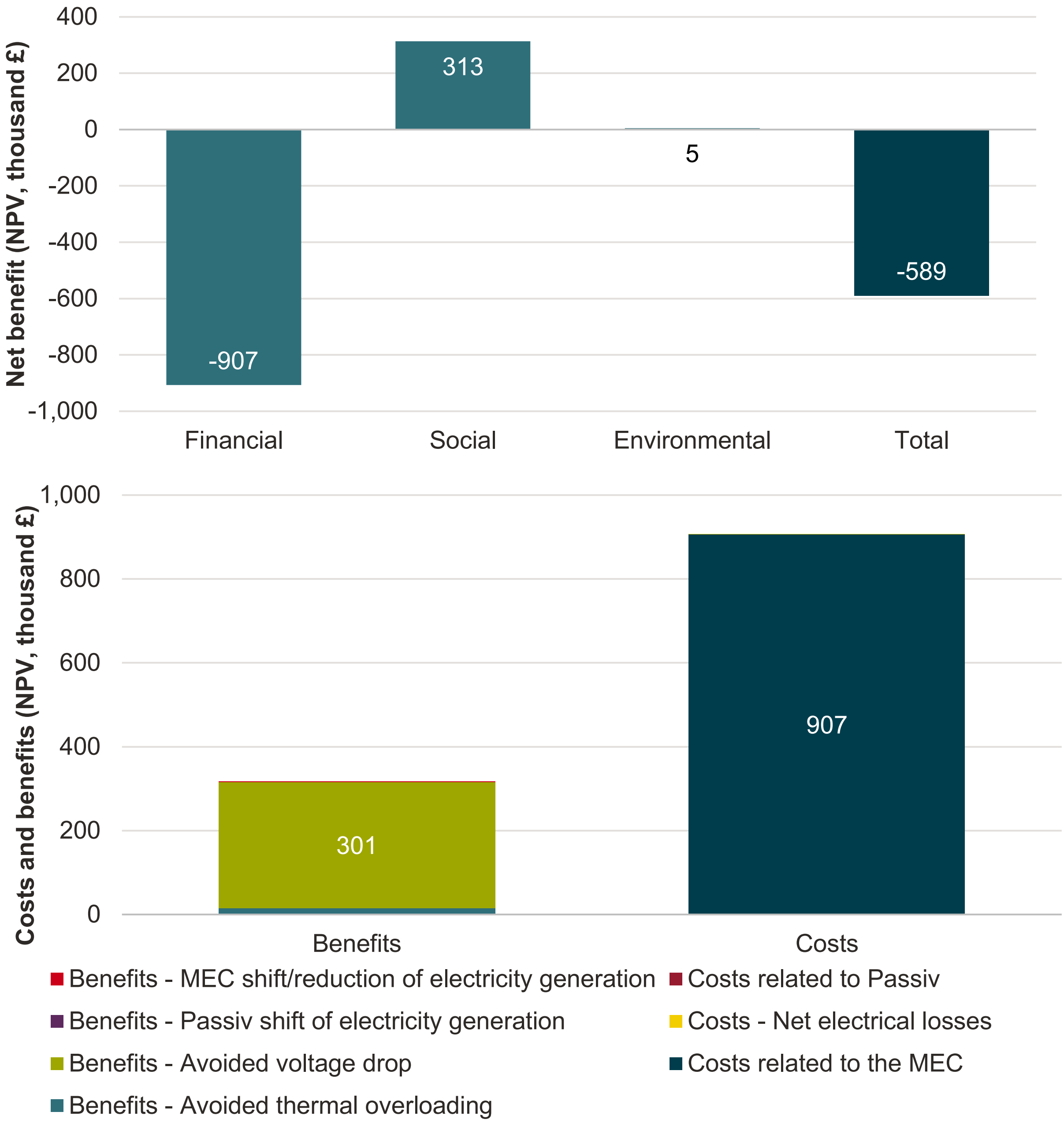
[40] The net cost remains above the 'no redeployment' cost even when site remediation costs are excluded. The increase is primarily driven by the relocation costs.

Figure 2 Scenario 1 - MEC with no PST flexibility benefits - BNZ



Source: Frontier Economics

Figure 3 Scenario 1 - MEC with no PST flexibility benefits - AAT



Source: Frontier Economics

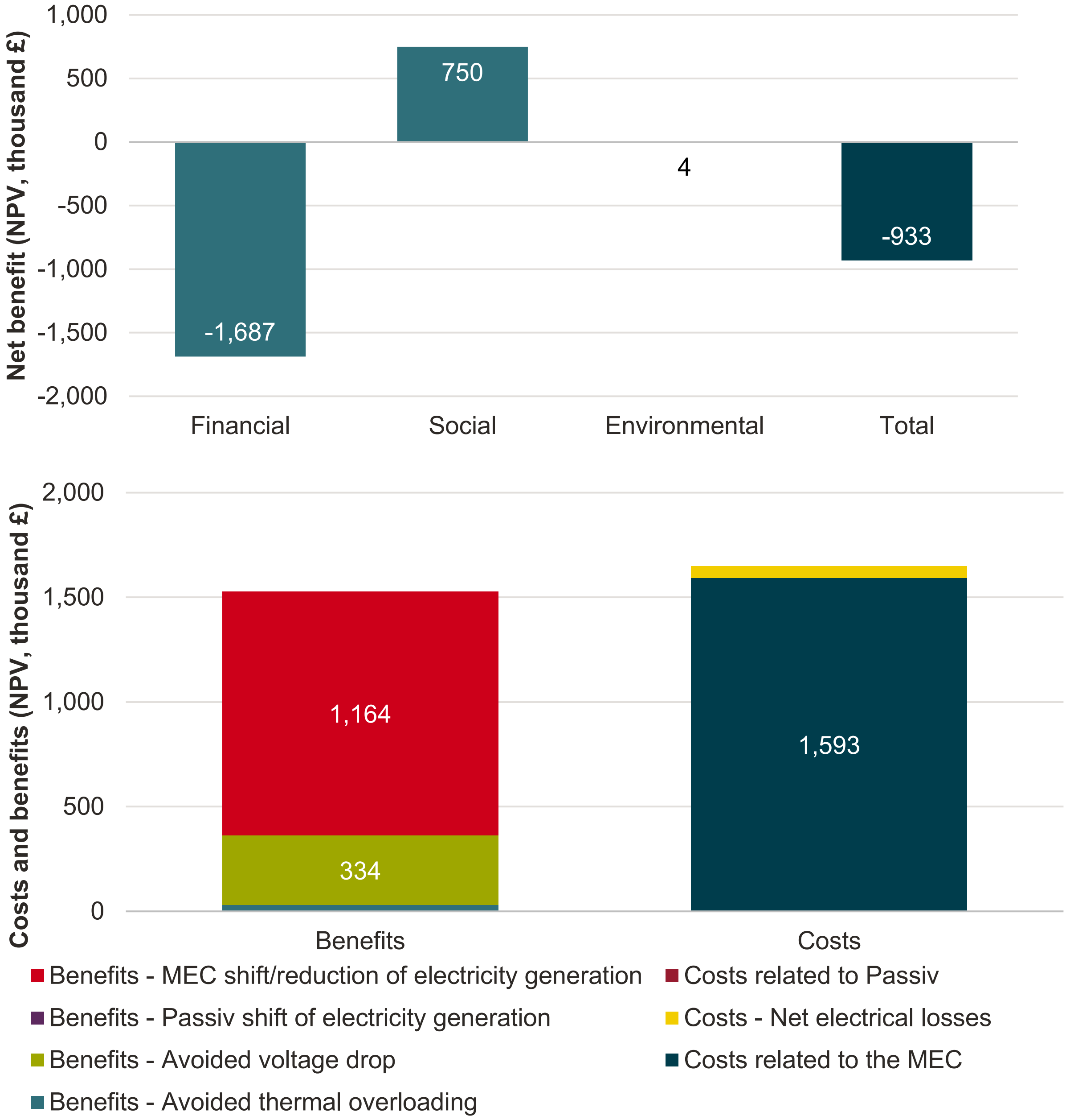
3.2.2 Scenario 2 – MEC with PST flexibility benefits

This scenario assumes household participation in flexibility markets (via heat pumps and smart thermostats) is zero in the counterfactual, but 100% in the intervention. Therefore, the additional driver of the benefits in this scenario is from flexibility services (with increased cost from deployment of PST to retrofitted heat pumps).

For BNZ, the CBA continues to produce net costs even in this case. The **net cost** is **£932k** (see Figure 4), around a third lower than the net cost in Scenario 1. There is additionally a rise in both societal and environmental benefits. Flexibility benefits are around £334k (with the costs of installing PSTs increasing costs by around £100k).

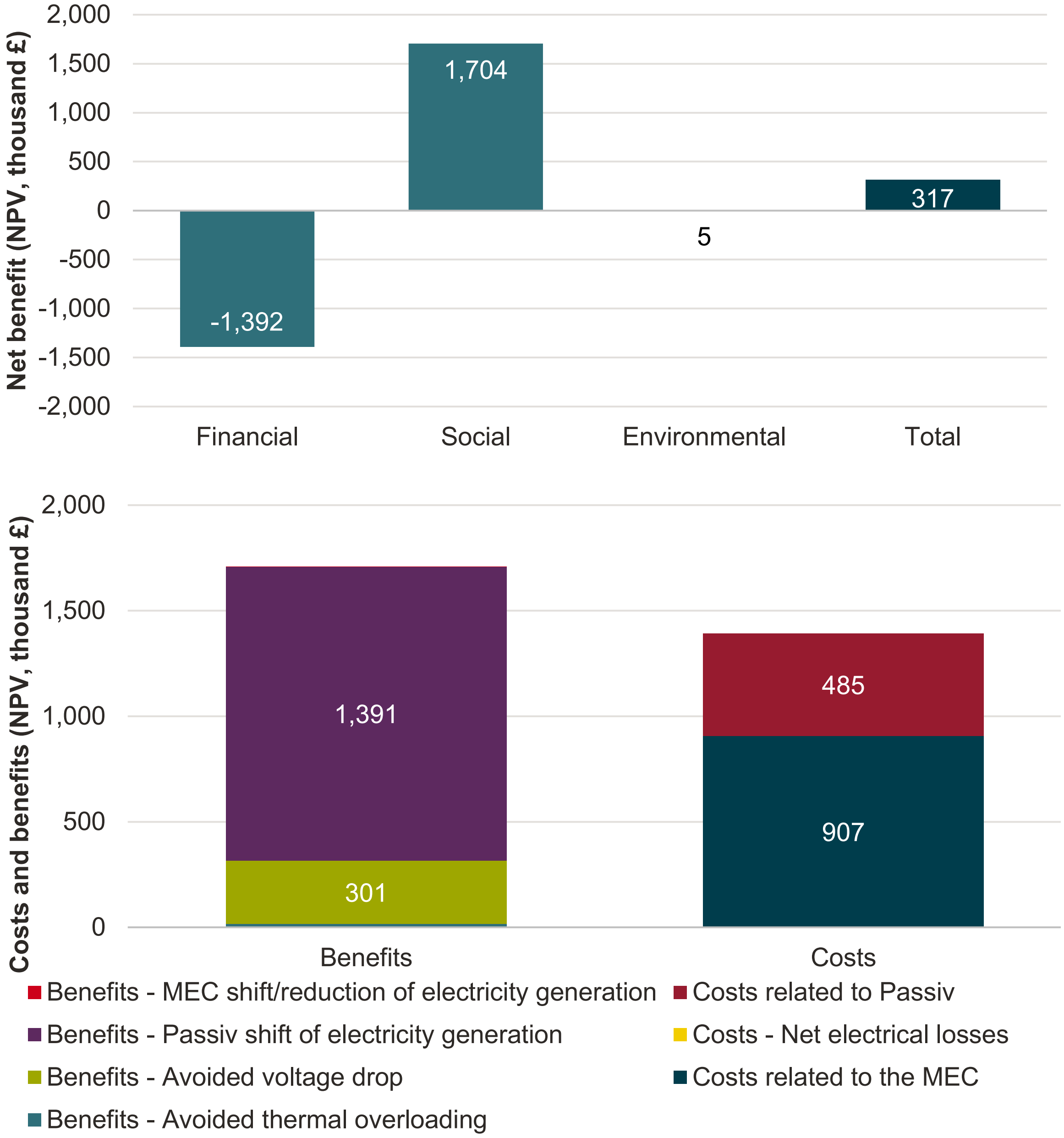
In AAT, there is a **net benefit** of **£317k** (see Figure 5). This positive result is driven by the net societal benefits from household heat pump participation in flexibility markets (£1.4m, only partially offset by the PST costs of £485k).

Figure 4 Scenario 2 – MEC plus PST flexibility benefits - BNZ



Source: Frontier Economics

Figure 5 Scenario 2 - MEC plus PST flexibility benefits – AAT



Source: Frontier Economics

3.2.3 Scenario 3 – MEC market participation with no PST flexibility benefits

This scenario is the same as Scenario 1, but additionally includes the additional benefits if the MEC can be used to shift demand outside of when it is required for the local constraint.

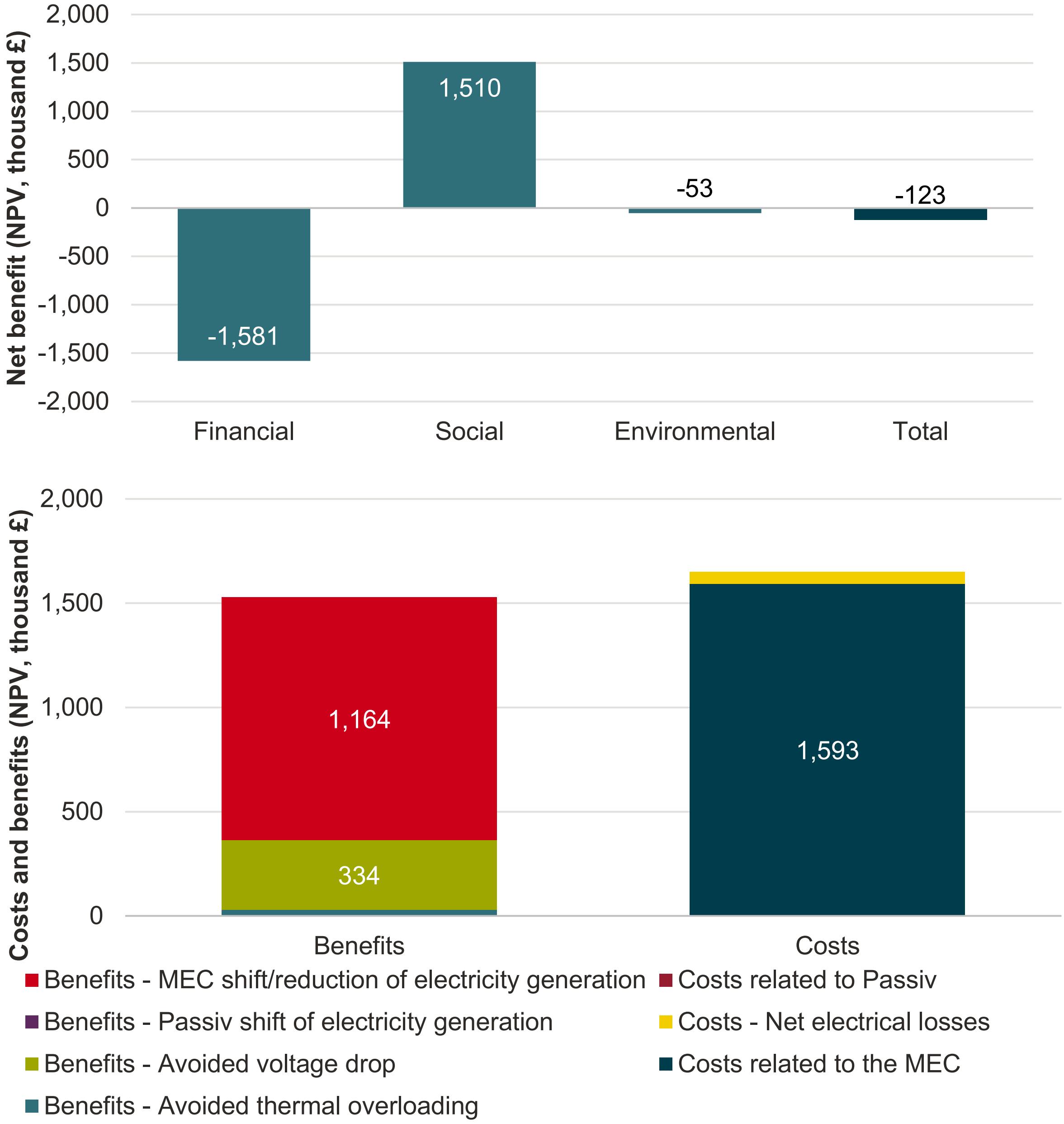
Compared to Scenario 1, financial net costs remain unchanged while societal benefits increase significantly. Environmental net benefits become negative because electrical losses from battery inefficiency increase significantly.

In BNZ, there are **net costs** of **£123k** (see Figure 6). However, when we consider an ‘enhanced’ version of Scenario 3, there is a net benefit of £54k. In this scenario we assume that: i) the risk of failure on the 33kV transformer increases to 4% in the counterfactual (compared to 2% in the intervention); and ii) the risk of failure on the 11kV transformer increases to 10% in the counterfactual (compared to 2% in the intervention). These assumptions are only illustrative and aim to demonstrate under what scenario a positive CBA could be achieved.[41]

In AAT, there are **net costs** of **£216k** (see Figure 7). The enhanced scenario does not achieved a positive CBA (net cost of £131k). In order to see a positive CBA, the risk of failure in the counterfactual must be 6% for the 33kV transformer and 21% for the 11kV transformer.

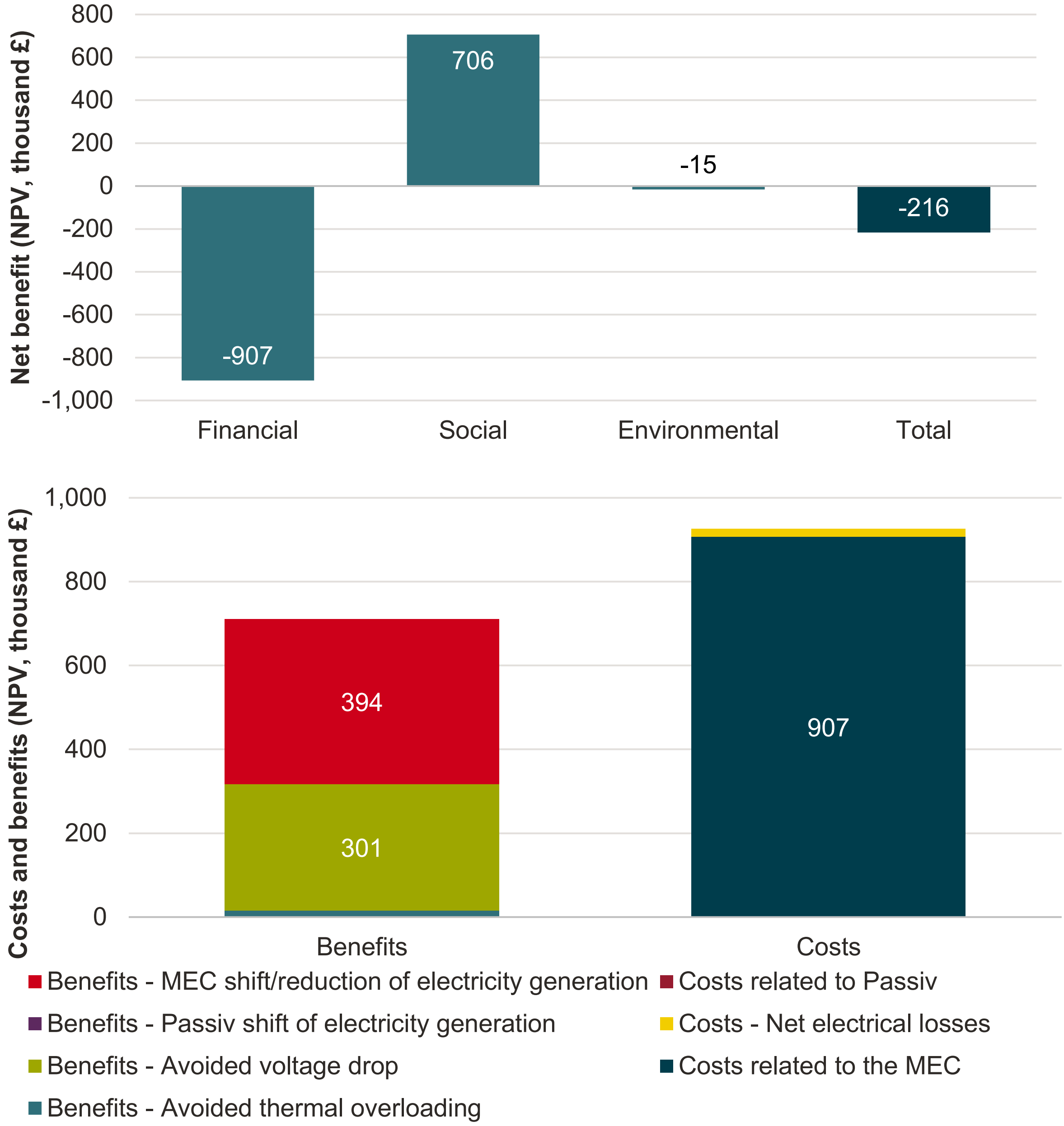
[41] The minimum increase in the risk of failure to see a positive CBA is 7% for the 11kV transformer.

Figure 6 Scenario 3 – Market participation with no PST flexibility benefits - BNZ



Source: Frontier Economics

Figure 7 Scenario 3 – Market participation with no flexibility benefits - AAT



Source: Frontier Economics

3.2.4 Scenario 4 – MEC market participation with PST flexibility benefits

This scenario is the same as Scenario 2, but additionally includes the additional benefits if the MEC can be used to shift demand outside of when it is required for the local constraint.

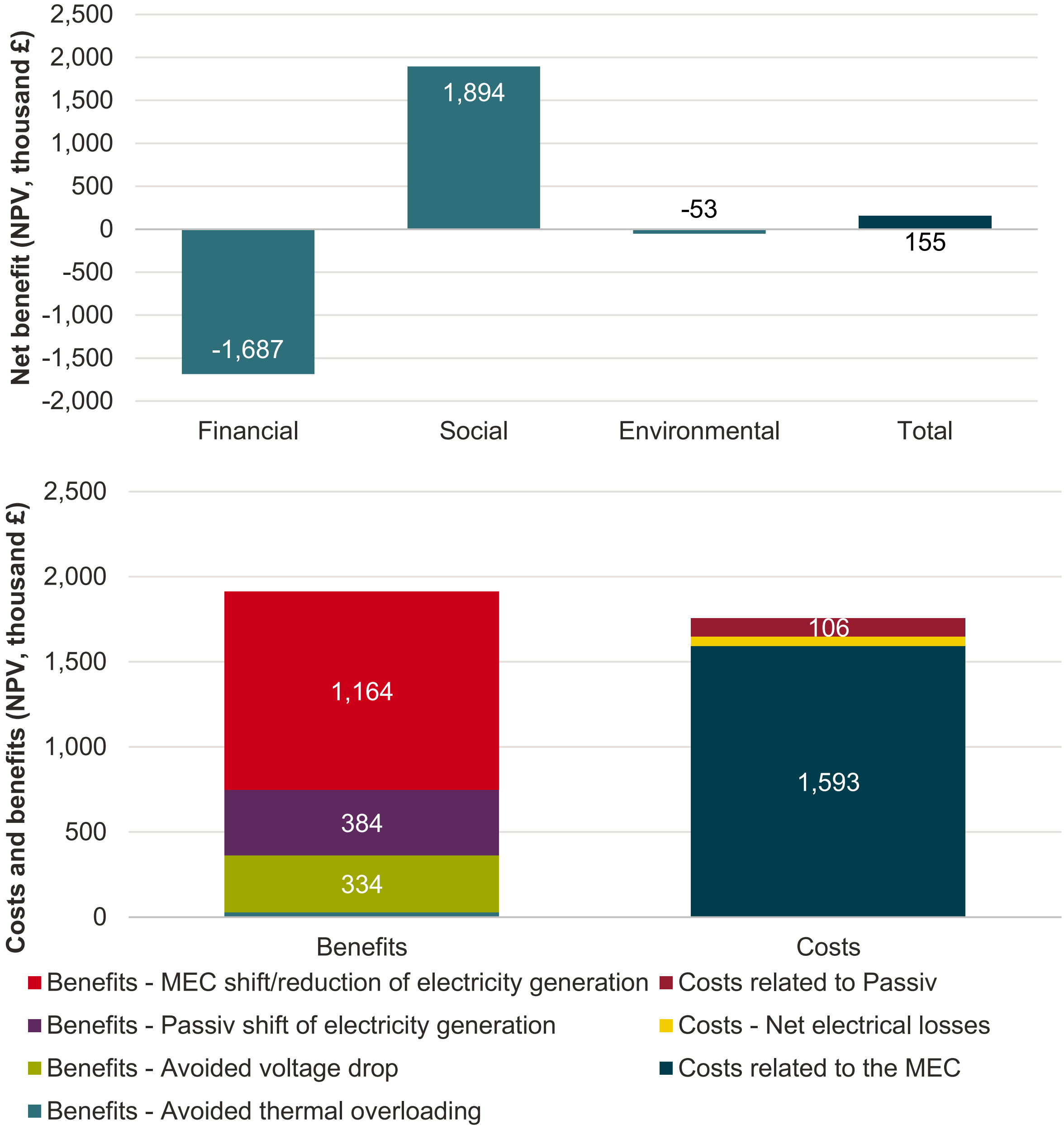
There is a net benefit in both communities.

In BNZ, the net benefit is **£155k**. Figure 8 shows the societal net benefits. Almost £1.2m of benefits come from flexibility revenues.

In AAT, the net benefit is **£690k** (Figure 9). Around £400m of net benefits come from flexibility revenues. Like Scenario 2, benefits continue to come predominately from PST flexibility.

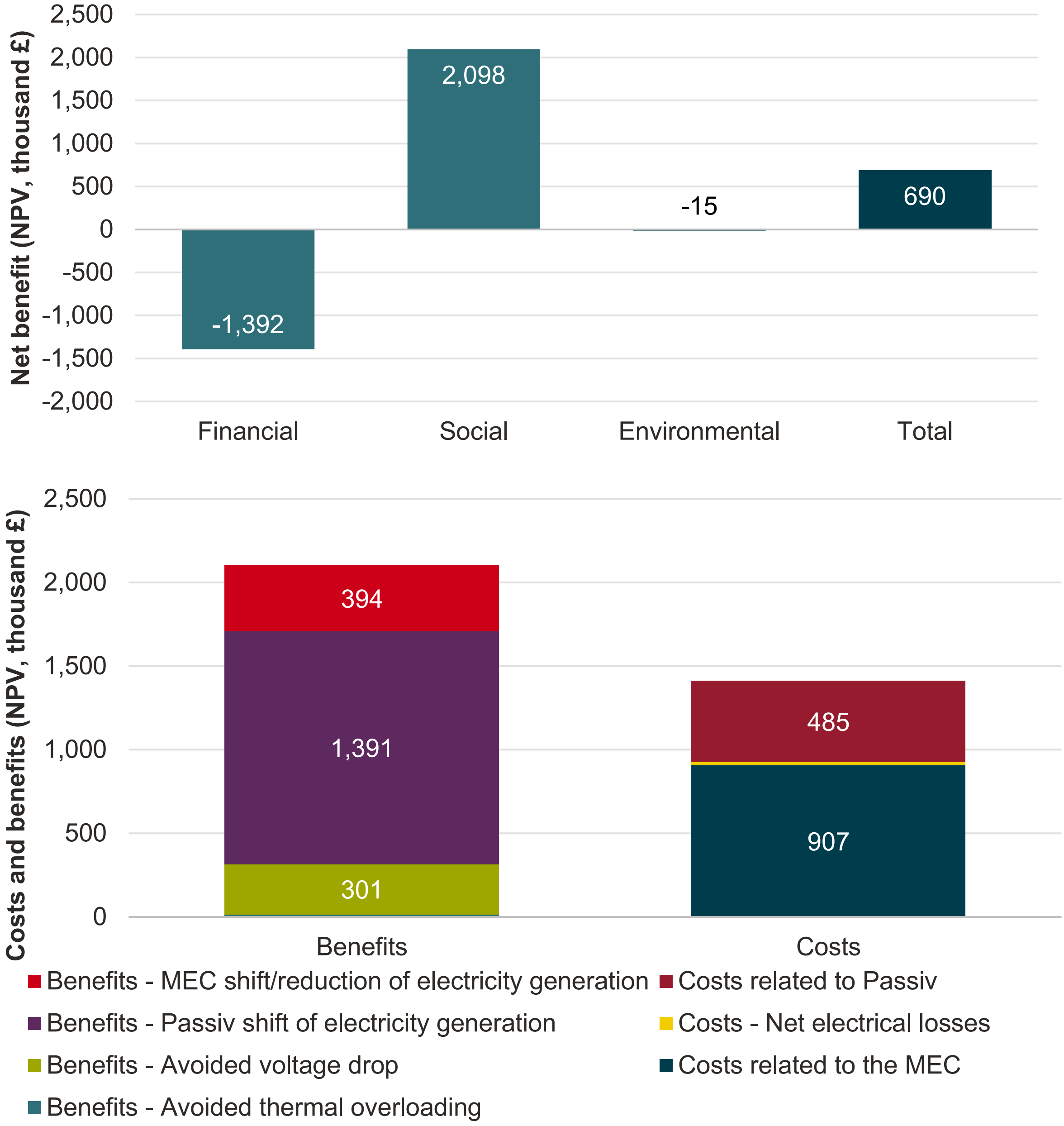
In BNZ, the battery is larger and so is able to generate much larger benefits from wholesale market participation.

Figure 8 Scenario 4 – Market participation with PST flexibility benefits – BNZ



Source: Frontier Economics

Figure 9 Scenario 4 – Market participation with PST flexibility benefits – AAT



Source: Frontier Economics

3.2.5 Wider rollout

The table below presents the CBA results when the REACH intervention is deployed more widely across both the NGED network and across GB.

In Scenario 1 and 3, both case studies have negative NPVs. We assume that the DNO would not rollout the intervention to areas with a negative NPV. We therefore assume no deployment so DNO-wide and GB-wide NPV is therefore zero.

In Scenario 2 and 3a (enhanced Scenario 3), we found that the NPV is positive in only one of the two case studies. We therefore assume that the MEC can only be rolled out to half of the sites identified in section 3.1.3, which are assumed to look similar to the results specified for AAT and BNZ respectively.

In Scenario 4, the NPV is positive in both the case studies. We calculate an average NPV across the two communities and assume rollout based on the approach described in section 3.1.3.

Table 3 CBA results across scenarios

	Rollout across sites	NGED deployment	GB deployment
Scenario 1 – MEC with no PST flexibility	None	0	0
Scenario 2 – MEC with full PST flexibility benefits	AAT spec only	£793k	£2.8m
Scenario 3 – Market participation with no PST flexibility	None	0	0
Scenario 3a – Market participation with no PST flexibility (enhanced)	BNZ spec only	£134k	£478k
Scenario 4 – Market participation with full PST flexibility benefits	Both BNZ and AAT spec	£2.1m	£7.5m

Source: Frontier Economics

3.2.6 Conclusions

The table below summarises the CBA results. Results indicate that the MEC will not deliver a net benefit to society unless the asset is able to participate in wider energy markets. Market participation is a key factor in achieving a positive cost-benefit result. A greater battery size (as is the case in BNZ) generates larger potential wholesale market revenues and therefore increases the likelihood of a positive CBA (as seen under Scenario 3 and Scenario 4). This result is intuitive since the MEC is a capex-heavy asset; without stacking value from market services, the asset is left inactive most of the year. The results from Scenario 3 show that the MEC (as sized for BNZ and AAT) may not always deliver a net benefit even if it can participate in the wholesale markets. However, more detailed analysis of the full set of revenues from 'stackable' market services would be needed in order to conclusively test this.

The results show that household participation in flexibility markets (via heat pumps and the PST) generates material benefits, leading to a net benefit for AAT under Scenario 2 and net benefits for both case studies under Scenario 4. However, similar benefits could arguably be realised in the counterfactual scenario, as in practice smart thermostats may be taken up by households who participate in heat pump flexibility, even in the absence of the REACH intervention.

Table 4 Summary of results across scenarios and communities

	BNZ	AAT
Scenario 1 – MEC with no PST flexibility	- £1.2m	- £589k
Scenario 2 – MEC with full PST flexibility benefits	- £932k	**+ £317k**
Scenario 3 – Market participation with no PST flexibility	- £123k ***+£54k in 'enhanced' version***	- £216k
Scenario 4 – Market participation with full PST flexibility benefits	**+ £155k**	**+ £690k**

Source: Frontier Economics

4 Ownership and commercial model

In this section we outline the set of options for the ownership and commercial model – i.e. which entities own which assets, and how revenues are recovered to cover the costs of installing and operating the REACH intervention. We then define and apply a set of criteria for evaluating the different options. We consider the MEC and the heat solution separately as the set of options and preferred commercial model differs between technologies.

4.1 MEC ownership and commercial model

4.1.1 Set of assets

The components that are part of the MEC are set out in section 2.2.1.

The generation and BESS components of the MEC would likely be owned by the same entity, due to the necessary integration of their operation. Further, similar issues are likely to arise for generation and BESS (e.g. relating to market participation) depending on the ownership model, so we consider the two components together. The additional modules allowing the DNO to control the technology would be owned by the DNO.

When the MEC is removed/relocated certain assets can be retained on site – the concrete slab that the MEC would be situated on and network connection infrastructure (11kV switchgear). The local community (or another third party) can use these assets to connect an asset, such as EV charge points, a BESS, or renewable generation.

4.1.2 Ownership options

Potential ownership options for the MEC[42] – during the initial phase where it is deployed to mitigate network constraints[43] – are:

- the asset could be owned by the DNO (subject to licence conditions, as discussed further below);
- the asset could be owned by a community organisation; or
- the asset could be owned by another third party (non-DNO) entity which could be a non-profit or a for-profit entity.

We describe each of these in turn below.

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42 With the exclusion of the control modules, which are always assumed to be owned by the DNO.

43 Beyond this initial phase (after network reinforcement is undertaken) we assume that DNO ownership would not be feasible as there is no longer a network constraint. Any asset that is installed following the removal of the MEC would therefore need to be owned by a community organisation of another third-party (non-DNO) entity. Evaluation of potential ownership models for any assets that are installed after the removal of the MEC is out of scope, given the nature of these assets is currently unknown.

DNO ownership

Under DNO ownership, the DNO would install and operate the MEC until network reinforcement is undertaken (and there is no longer a risk of network overloading). The DNO may then redeploy the MEC to another location on its network.

To install the asset the DNO would need to identify a suitable site, get permission to use it from the landowner and secure any required planning permission.[44] The DNO would presumably engage with the community in order to gain wider 'buy in' for the MEC. The DNO would also need to engage with the third party owner of the heat solution which is expected to be installed alongside the MEC.

The DNO would pay upfront MEC installation costs, ongoing operational and maintenance costs, and removal/redeployment costs. Subject to the approval of DNO ownership, it is anticipated that the DNO would finance the capital and operational costs of the MEC asset. In an NGED or GB-wide rollout (i.e. beyond any Beta phase) it is anticipated that this investment would need to be justified by DNOs as part of their business plan (or reopener) submissions and would be subject to Ofgem's cost assessment process. If allowed, the costs associated with the MEC would be recovered through DNO allowed revenues (as part of load related expenditure).[45]

Regulatory requirements for DNO ownership

Compared to other ownership models, strict regulatory requirements would apply. Licence conditions generally restrict DNOs from owning or operating generation (or storage due to its classification as a form of generation),[46] which would be part of the MEC. However, there are three exceptions:

- Category A exception: The DNO can own or operate assets as part of island networks solely for the purpose of ensuring security of supply.
- Category B exception: The DNO can own or operate assets situated on the distribution network for specific purposes including continuity of supply, system resilience or energy management. However, the DNO is not permitted to use the asset to buy or sell electricity in energy markets. Ofgem's Prohibition on Generating Guidance (POGG)[47] specifically identifies the types of activities that it would consider to fall under this exception:

44 NGED is of the view that some level of planning permission would be required. Further work would be required at Beta phase to determine the exact requirements, depending on the location of the MEC.

45 Under the RIIO-ED2 price control, investment in flexible solutions is treated as load related expenditure.

46 This is set out in Condition 31D Part A and 43B Part A of the Standard conditions of the Electricity Distribution License. See: https://www.ofgem.gov.uk/sites/default/files/2023-03/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current.pdf

47 Further detail on specific authorised activities is set out in Ofgem (2021). Prohibition on Generating Guidance (POGG), Section 2. See Section 2: https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/pogg_latest_update_may2021_0.pdf

  - Uninterruptible power supply: Devices used at substations and other licensee sites to ensure that critical equipment remains energised in the event of a system outage, thereby allowing the licensee to safely manage its systems.

  - Emergency response: Devices with generation capability connected to the licensee's network by the licensee for the sole purpose of ensuring continuity of supply in specific outage situations (such as faults or maintenance outages).

  - Energy management at licensee-owned sites: Devices with generation capability with the sole purpose to generate or conserve electricity produced at licensee sites for later consumption at that same site.

- Category C exception: Ofgem can issue a direction allowing the DNO to own or operate the asset in cases where the DNO has:[48]

  - taken reasonable steps to obtain a market-based solution;
  - justified that a DNO operated asset provides the most economic and efficient solution; and
  - put in place arrangements that minimise the risk of discrimination or distortion of current and future markets.

The Category A exception is not relevant for the REACH intervention as the MEC would be located on the distribution network (rather than as part of an island network).

The Category B exception would not be suitable for the REACH intervention, as the types of activities the exemption permits (described above) are not the activities provided by the MEC.

There may be a route to DNO ownership through the Category C exception, but only on parts of the network where the DNO has been unable to secure required flexibility through DSO markets. This is an area that could be explored further should the project progress to Beta phase. In this case, the DNO would be able to directly provide a flexibility service via the MEC to meet the local need on the 11kV network, but it is not expected that the DNO would be able to provide flexibility services more widely or participate in energy markets. The DNO would not receive payments for providing a flexibility service, but could recover the costs of the MEC through the RAB revenue model.

There may be scope to use Ofgem's regulatory sandbox to allow DNO ownership for a proof of concept trial of the MEC (e.g. at Beta phase). However, it is not expected that the sandbox could be used as an enduring solution, as the sandbox is intended to provide time-limited derogations from specific rules, rather than enduring derogations.[49] This would require further exploration in the lead up to or at Beta stage, should the REACH project progress.

48 Category C exceptions may be issued for a limited period of time and may have specific conditions attached.

49 See: https://www.ofgem.gov.uk/publications/energy-regulation-sandbox-guidance-innovators

Community ownership

Under community ownership, a community group (or an entity contracted on its behalf)[50] would need to work with the DNO to determine the network need/value case for the MEC and to secure a connection agreement. The community group (or an entity contracted on its behalf) would then install and operate the asset. A contract would be required between the asset owner and the DNO to ensure that the MEC would operate to meet the need on the 11kV network, when required.

Given that groups such as community energy organisation tend to be small and asset-light, it is not expected that a group would be able to raise substantial capital, take on project or revenue risk, or manage the operations of the MEC (including participation in energy markets). A shared ownership and funding model may therefore be required.

After network reinforcement is undertaken (and there is no longer a risk of network overloading) the community group could opt to continue with the MEC, or it could be redeployed to another community where there is a network need. If the MEC is removed/redeployed, the community could use the residual assets (concrete slab and connection infrastructure) to install further assets of their choosing.

The community group would need to work closely with the DNO and would also need to engage with the third party owner of the heat solution (discussed in section 4.2) which is expected to be installed alongside the MEC.

The community group, under some form of financing arrangements (and potentially a shared ownership and financing model), would pay upfront MEC installation costs, ongoing operational and maintenance costs, and removal/redeployment costs. The community group (or an entity contracted on its behalf) could secure payment/revenues for providing a service to the DNO to meet the need on the 11kV network, and through participation in energy markets such as DSO flexibility markets, the wholesale electricity market, and ESO markets.[51]

Other third party ownership

Third-party ownership would be similar to community ownership, except this model would be more market driven with less support and guidance provided by the DNO. The third party would need to secure a connection agreement, and then would install and operate the asset. A contract would be required between the asset owner and the DNO to ensure that the MEC would operate to meet the need on the 11kV network, when required.

After network reinforcement is undertaken (and there is no longer a risk of network overloading) the third party could continue operating the MEC or could redeploy it to another

50 For example, a community energy group may own the asset but may sub-contract to an organisation with expertise in procuring and managing electrical assets.

51 Such as the balancing and capacity markets.

location where there is a network need. If the MEC is removed/redeployed, the third party could decommission the site, or alternatively the residual assets could be sold, leased or gifted to another party (which could in theory be the community).

The third party would need to engage with the community in order to gain community acceptance of the MEC. It would also need to engage with the owner of the heat solution (discussed in section 4.2) which is expected to be installed alongside the MEC. The third party would pay upfront MEC installation costs, ongoing operational and maintenance costs, and removal/redeployment costs. It would need to secure revenues for providing a service to the DNO to meet the need on the 11kV network, and through participation in energy markets such as DSO flexibility markets, the wholesale electricity market, and NESO markets.[52]

A third party ownership model should largely be able to be enacted under current regulatory and commercial frameworks.

4.1.3 Assessment of potential options

Evaluation criteria

We apply the following criteria to evaluate MEC commercial model options:

- **Regulatory restrictions on ownership:** We consider regulatory restrictions to be a 'hurdle' criterion – i.e. a party either passes or fails this test. As outlined above, there are restrictions on DNO ownership of generation and storage assets that do not apply for community and third party ownership. Should the REACH project progress to Beta phase, further work would be needed to explore whether there are allowable options for DNO ownership such as use of Ofgem's regulatory sandbox (for a trial) or a Category C exception from current licence conditions.
- **Success and speed of implementation:** Different parties will have varying levels of the knowledge and capabilities required to deploy the MEC successfully and at pace. Additionally, more complex contracting requirements under certain ownership models may mean longer timelines for deploying the MEC once a network need is identified.
- **Net cost:** While costs and benefits are explored in detail and quantified in section 3, here we set out at a high level the expected net cost under different ownership models – i.e. considering the scale of the benefits that are likely to be generated under each ownership model relative to the cost of the asset.
- **Scalability:** The ability to quickly and extensively scale the intervention will vary under different ownership models.

Table 5 sets out the assessment of each ownership model across the four criteria.

52 Such as the balancing and capacity markets.

Table 5 Evaluation of MEC ownership options against criteria

Criteria	DNO ownership	Community ownership	Third-party ownership
Regulatory restrictions (hurdle criterion)	Unknown. DNO would need to meet exemption criteria under current licence conditions, or successfully apply to use Ofgem's regulatory sandbox.	Green. No regulatory restrictions on community ownership, subject to securing connection agreement from DNO.	Green. No regulatory restrictions on third party ownership, subject to securing connection agreement from DNO.
Success and speed of implementation	Green. DNO has substantial knowledge and capabilities required to install and operate the MEC. Not having to contract with asset owner would allow for fast implementation, although some contracting (e.g. with landowner) would still be required.	Red. Community may not have sufficient knowledge and capabilities to install and operate the MEC (although could contract with an organisation to procure and manage asset on their behalf). Contracting with DNO (and other parties such as landowner) would add time.	Amber. Commercial incentive for third-parties successfully install and operate the MEC, and only enter if they have sufficient knowledge and capabilities. However, contracting with DNO (and other parties such as landowner) would add time.
Net cost	Red. DNO may be restricted from participating in energy markets, reducing the benefit provided by the asset relative to its cost.	Green. No restrictions on participating in energy markets, allowing the asset to optimise and deliver maximum benefits relative to cost.	Green. No restrictions on participating in energy markets, allowing the asset to optimise and deliver maximum benefits relative to cost.
Scalability	Green. Can be easily replicated by DNO across network, including by re-deploying MEC multiple times across its asset life.	Red. Would require active participation by multiple communities. Higher barriers to redeployment as community would need to be willing to redeploy and a suitable new community identified	Green. Third-parties may be able to scale successfully but will depend on the size of the third party.

4.1.4 Conclusions

In the near-term, the priority is to ensure timely and successful installation and operation of the MEC to address the risk of network overloading. DNO ownership is expected to be the optimal model for achieving this in the near-term where proof of concept needs to be developed and if there are no suitable third-parties who can provide the service to the DNO. However, DNO ownership would be conditional on the DNO securing an exemption under current licence conditions or successfully applying to use Ofgem's regulatory sandbox (for a trial). It is not anticipated that the DNO would be permitted to participate and earn revenues in energy markets, even if an exemption to restrictions on ownership of generation and storage assets was secured. This means that a DNO ownership model performs poorly on the net cost criteria. As illustrated in section 3, the MEC is not expected to deliver a net benefit unless it is able to participate in energy markets.

Ownership by a third party (which could in theory be a community with sufficient capabilities and interest) could present a viable option, particularly if there was a specialised party who could deploy the asset (including redeployment) across DNO licence areas. A key benefit of third party ownership is that the asset would be able to participate in energy markets (as well as meeting the local network need), maximising the benefits that can be delivered.

There may be scope for a hybrid approach to be implemented, where the DNO has responsibility for installing and financing the MEC, but leases the asset to a third party (e.g. the community), who could control operation of the asset and participation in energy markets at times where the asset is not required to meet the local need on the 11kV network. This would require further exploration and engagement with Ofgem should the project progress to Beta phase. It would be important to ensure that leasing arrangements do not undermine fair access or have a distortionary impact on energy markets.

A DNO or third party ownership model can still offer benefits to the local community, particularly when the MEC is removed/relocated (after network reinforcement is undertaken) and the community has the option to use the residual assets and connection to install a community owned asset of its choosing, which may allow for faster and cheaper installation than if the MEC had not been deployed.

4.2 Coordinated heat solution ownership and commercial model

4.2.1 Set of assets

The heat solution is comprised of Passiv smart thermostats (PST), which can be installed alongside new heat pumps or retrofitted for existing heat pumps. Coordinated control of heat pump operations can reduce aggregate peak demand at the community level. This can reduce the risk of network overloading and therefore the size of the MEC that would be needed to address this risk.

4.2.2 Ownership model

We assume that households would own the PSTs, but the coordinated heat solution would be owned by a third party, who would engage with the community and the owner of the MEC. It would implement the coordinated heat solution, using its IP and other technologies supporting the smart thermostats.

After network reinforcement is undertaken (and there is no longer a risk of network overloading) the PSTs would be retained by households. When PSTs reach the end of their asset life, it is expected that many would be replaced like-for-like as the cost is similar to a non-smart thermostat. Community engagement by the DNO and/or the third party owner of the heat solution would be needed to ensure sufficient uptake of the PST.

Households would pay upfront PST installation costs (either alongside a new heat pump, or retrofitting an existing heat pump). Households can receive revenues from aggregated participation in flexibility markets – i.e. via Passiv's technology households can participate in NESO's Demand Flexibility Service (DFS).[53] Households on time-of-use tariffs can also optimise heat pump operation to generate energy bill savings – however bill savings are not expected to be a material revenue stream while the MEC is installed, as optimising for bill savings will not necessarily correspond with optimising to reduce aggregate peak load. DFS revenues, however, are expected to be a potential revenue stream to the extent there is overlap between peak demand periods at the transmission and distribution network levels.

The third party owner of the heat solution would need to cover the costs of developing and implementing the coordinated heat solution (such as running the algorithm and server). It would receive revenues from household purchases of PSTs, and a portion of revenues from aggregated participation in flexibility markets.

53 See: https://www.passivuk.com/insight/demand-flexibility-service-using-passiv-smart-controls-to-support-the-national-grid-by-tom-latimer-passiv-algorithm-developer/

5 Financial flows

Cost-benefit analysis asks whether the REACH intervention is beneficial for society, considering all potential costs and benefits. In this section, we consider whether the REACH intervention stacks up financially for the potential owners. The result of the financial flow modelling may differ from the cost-benefit analysis if there are externalities (such as wider social benefits) which would not be factored into financial flows.

We use the CBA modelling to calculate and illustrate, at a high level, the financial flows that would occur between different parties under the ownership and commercial models set out in section 4.

MEC financial flows under a DNO ownership model

Subject to the approval of DNO ownership, it is anticipated that the DNO would finance the capital and operational costs of the MEC asset. In an NGED or GB-wide rollout (i.e. beyond any Beta phase) it is anticipated that this investment would need to be justified by DNOs as part of their business plan (or reopener) submissions and would be subject to Ofgem's cost assessment process. If allowed, the costs associated with the MEC would primarily be recovered through DNO allowed revenues (as part of load related expenditure).[54]

Assuming redeployment five times, the capital costs of the MEC are £1.23m using BNZ specifications and £0.91m using AAT specifications (undiscounted). The annual operational costs are roughly £37k for BNZ specifications and £13k for AAT specifications (undiscounted). Under a DNO ownership model it is assumed that capex is capitalised in the RAV and opex is expensed (recovered in-year).[55] Under a non-DNO ownership model it is assumed that discounted revenues from services provided by the MEC would need to exceed the discounted costs of the MEC (factoring in financing costs) in order for the MEC to be a viable business proposition.

MEC financial flows under a non-DNO ownership model

As outlined in the CBA section above, there are additional benefits that could be delivered by the asset should it be able to operate to provide a broader set of flexibility services beyond the local need on the 11kV feeder. For example, the MEC can provide additional electricity supply via the genset, or shift the timing of demand/supply via use of the battery. This can provide an energy system benefit by helping to match lower cost and lower emissions generation with demand.

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54 Under the RIIO-ED2 price control, investment in flexible solutions is generally treated as load related expenditure.

55 Under the RIIO model a proportion of capex *and* opex (totex) is capitalised into RAV, according to the capitalisation rate. However, for the purposes of this analysis we assume that all capex is capitalised into the RAV and that opex is covered in year. This is due to the setup of the SIF template.

A number of markets and business models are already established that provide revenue streams to compensate providers of flexibility services. As part of the CBA we have undertaken illustrative modelling of the potential benefits arising from the MEC battery participating in the wholesale market. With BNZ specifications, the NPV of these revenues over the 15-year life of the MEC is £1.18m, which corresponds to a negative NPV of the MEC of £340k. With AAT specifications, the NPV of revenues is £450k, corresponding to a negative NPV of the MEC of £500k. This indicates that wholesale markets alone are not a viable business model for a non-DNO owner.

The MEC would be able to secure revenues from the DNO for the provision of a flexibility service in response to the need on the local 11kV network. The network's maximum willingness to pay for this service would be equal to the value provided by the MEC in terms of avoided power quality issues (avoided voltage constraint) or risk of asset failure (avoided thermal constraint).

It is possible that the MEC could secure additional revenues from providing services in the balancing market, which can be 'stacked' on top of revenues from the wholesale market. The MEC could also potentially earn revenues from providing services in the capacity market or DSO flexibility markets. Further work would be needed assess the full set of services that could be provided by the MEC, the stackability of different services, and the potential revenues that could be earned.

Coordinated heat solution financial flows

As outlined in the CBA section above, it is assumed that households would finance the capital costs of installing the PSTs, as this would be similar to the costs of installing a standard thermostat. For new heat pump installations, this means that no additional costs would be incurred by the customer (relative to the counterfactual). Customers retrofitting PSTs to existing heat pumps would incur an estimated cost of £220 (assuming a 1-zone PST). However, customers would be able to earn revenues from participation in flexibility markets via Passiv. As an illustrative example, it is estimated that customers may earn £72 per year from participation in NESO's Demand Flexibility Service (DFS). This equates to a positive NPV of £384 over a 10 year PST asset life, indicating that the PST is a financially viable investment for customers.

6 Overall conclusions and next steps

This work has demonstrated that, under certain circumstances, the combination of the MEC and PSTs can provide an overall net social benefit. However, even under the most favourable scenarios, the implied GB-wide benefit may make it difficult to justify the level of additional investment usually carried out for a SIF Beta phase.

There are nevertheless a large number of uncertainties, and further research might demonstrate that this approach is worth pursuing further. This would need to:

- Produce estimates of the value of an individual intervention to the network itself, grounded in engineering and consumer research, that would warrant DNO investment in REACH assets;
- demonstrate that the intervention will have a sufficiently wide application; and
- confirm that a regulatory model exists that enables 'value stacking' while giving the DNO sufficient control.

We discuss these in turn below.

6.1 Further work is needed to confirm the drivers of value for the network

The driver for the DNO (rather than another entity) to invest in these assets is to mitigate problems caused by higher than expected demand. However it has been difficult to place an exact value on these benefits, which are not covered by the standard SIF CBA methodology.

As an initial next step, we suggest that further work is carried out to place bounds on this value, as they are ultimately what will drive the amount which the DNO is willing to pay for solutions such as REACH. This might include:

- Technical analysis to determine the relationships between voltage drop and power quality issues, and surveying customers to determine the value that customers place on power quality.

- Modelling to robustly quantify the value associated with reducing thermal constraints – specifically, technical analysis to determine the relationship between network overloading, thermal constraints arising, and the probability of asset failure (which can then be quantified through the CNAIM).

6.2 The number of areas which might benefit from REACH is currently unclear

As explained in section 2, the interventions being investigated by this project are intended for use in a very specific set of circumstances where:

- network capacity is about to be exceeded;
- adequate support is not available from flexibility markets; and
- this has occurred sufficiently quickly and unexpectedly that it has not been feasible to reinforce the network in time.

With accelerating LCT rollout under a 'connect and notify' approach, unforeseen clusters of LCTs might lead to this occurring more often. This is an extremely important issue, which is generally not considered when DNOs apply current tools like the Common Evaluation Methodology (CEM)[56] (which always assume that reinforcement can be carried out in time to keep the network within constraints).

In section 3 we used an assumption from NGED that 25 communities may require the intervention across its network. However, to properly understand how often an intervention like REACH would be applied (and therefore develop a better estimate of GB-wide value), further research would be needed to understand the likelihood of unforeseen LCT clustering (the trigger for the REACH intervention) occurring on the distribution network.

6.3 The business model should enable 'value stacking' for the battery

The CBA has shown that, without including the wider benefits of PSTs,[57] the MEC needs to participate in wider energy markets in order for the scheme to have a positive net benefit in any of the case study areas. This result is subject to the uncertainties around valuing the network benefits described above. However, without value stacking, an expensive battery will be left unused for much of the year, which is clearly an uneconomic use of an asset.

This indicates that it is critical that the MEC is able to participate in wider energy markets. As this is restricted under DNO ownership, this suggests that a third party or hybrid ownership model is required, with the DNO sufficiently distanced from ownership and operation to satisfy regulatory requirements. However this raises a tension: The whole point of REACH is to provide a 'solution of last resort' for resolving network issues in areas where the market cannot deliver sufficient flexibility, and there is no time available for traditional reinforcement. This implies that a strong level of DNO control (if not ownership) will be required to ensure that the intervention is brought forward and used when and where it is needed.

Discussions with Ofgem may help to understand whether there is a regulatory arrangement which can meet these competing needs.

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56 See: https://www.energynetworks.org/publications/common-evaluation-methodology-tool-and-supporting-materials

57 The significant return to PSTs suggests that customers would be incentivised to install them *without* the intervention of the DNO. While some customers might not install a PST themselves despite the financial benefits, they would likely not be swayed by any additional financial benefits a DNO could provide. We therefore recommend that these benefits of the PSTs should *not* be included as part of the overall CVA for REACH. However the benefits to heat flexibility are clearly substantial, and it is certainly worthwhile ensuring that networks have the ability to draw on the flexibility provided by smart thermostats.

Annex A – Additional data

Table 6 sets out the number of customers with the Passiv heat solution for each archetype community, assuming a 10 year asset life and deployment across 5 communities.

Section 3.1.1 explains our high level approach. For example, in BNZ the MEC is moved in 2029. Therefore, heat pump uptake in 2029 is equal to heat pump uptake in one community in 2028 (since we do not include heat pumps installed after the MEC is moved) plus heat pump uptake in another community in 2029.

Table 6 Uptake of the Passiv heat solution

	BNZ	AAT
2026	67	0
2027	73	0
2028	79	0
2029	164	153
2030	173	203
2031	182	253
2032	294	556
2033	303	605
2034	312	655
2035	453	1,132
2036	398	1,207
2037	403	1,282
2038	573	1,983
2039	499	1,904
2040	491	1,899
2041	482	2,715
2042	370	2,457
2043	361	2,452
2044	352	2,402
2045	211	1,925

	BNZ	AAT
2046	35	404
2047	24	329
2048	12	255
2049	1	180
2050	0	135
2051	0	90
2052	0	45
2053	0	0
2054	0	0
2055	0	0

Source: Frontier Economics, based on DFES (provided by Passiv)