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Electricity System Benefits of Heat Networks

ADE Research

Research Demand Heat Networks

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ELECTRICITY SYSTEM BENEFITS OF HEAT NETWORKS

This work was conducted by ADE Research, in collaboration with Dr Shahab Dehghan (Newcastle University) and Dr Marko Aunedi (Brunel University). Drs Dehghan and Aunedi operated the Whole electricity System (WeSIM) model on behalf of ADE Research on a subcontractor basis.

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Executive Summary

This study demonstrates the electricity system benefits of heat networks for the UK's energy system by 2050, using the Whole Electricity System Investment Model (WeSIM). It builds upon prior research quantifying system cost savings from renewable integration and flexibility enhancements, while expanding the scope to include capital expenditures, dynamic heat demand projections, spatial variability, and a diverse mix of heat generation technologies. We modelled scenarios in two separate stages: first, we modelled an ambitious roll-out of heat networks in which all other parameters, relative to our baseline, are kept constant; we then tested further scenarios to explore a diverse range of possible futures in which heat networks might develop.

We find that the deployment of heat networks leads to net benefits for the wider electricity system across a range of areas, namely:

- A decrease in infrastructure-related CAPEX: across urban and semi-urban areas, it is cheaper to invest in heat networks than it is in individual Air Source Heat Pumps (ASHP)
- A reduced burden on the grid, namely decreases in the need for grid reinforcement, upgrades and maintenance
- A reduction in the installed generation capacity required to produce the electricity needed for electrified heat

Collectively, these equate to an annualised net benefit of £3.5 bn a year that is directly attributable to the ambitious deployment of heat networks with large-scale, flexible thermal storage. By 2050, these cumulative net benefits reach £86.5 bn.

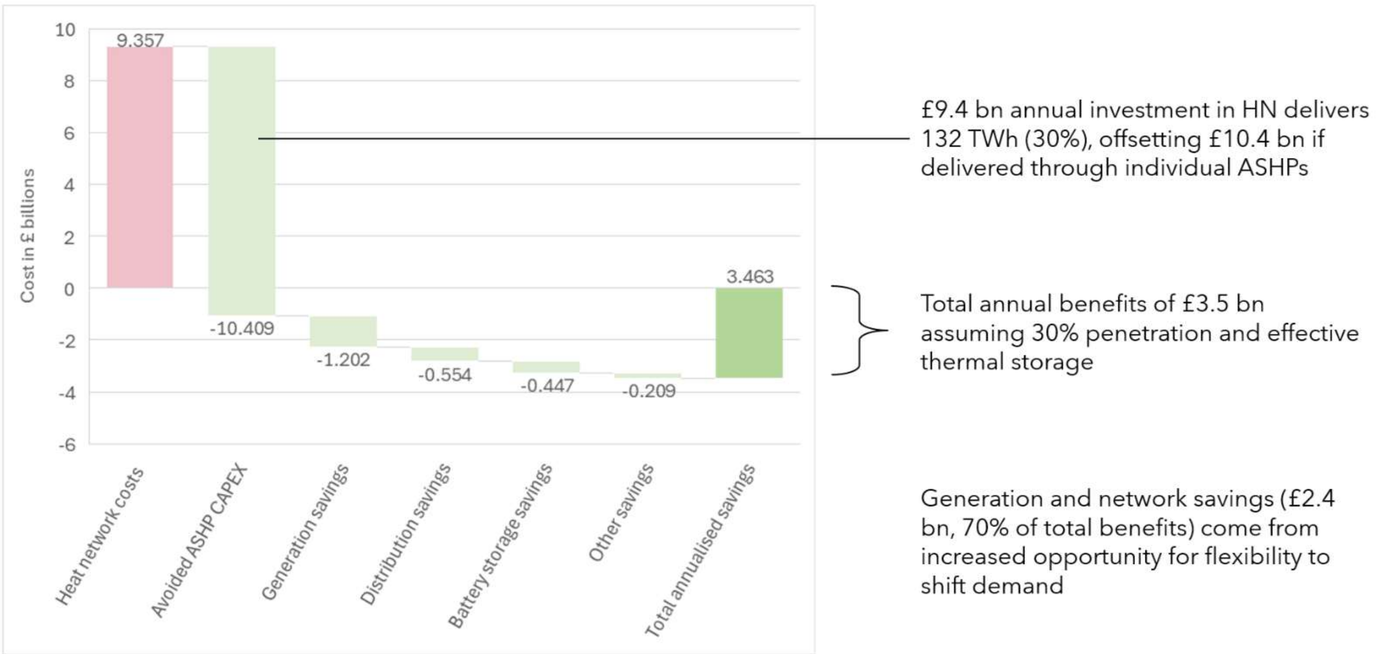
These £3.5 bn a year in cost savings are broken down as follows:

- The net savings from investing in heat networks in urban and semi-urban areas, rather than individual ASHPs, come to £1.1Bn a year.
- We see £1.2Bn a year of generation savings through a reduction in installed generation capacity.
- We see distribution savings (the investment and operation costs for the low-voltage networks that deliver electricity from substations to end consumers) of £0.6 bn a year.

- Collectively, the net benefits for the broader electricity system across generation savings, distribution savings and other savings across the grid and battery storage come to £2.4 bn a year.
- When we include the net savings of £1.1 bn a year from investing in heat networks, rather than individual ASHPs, we get the total annual net benefit of £3.5bn a year.

These findings are illustrated in Figure 1:

Figure 1: net cost benefits of heat networks (main scenario)



Key conclusions

- It is considerably cheaper to invest in heat networks than it is in individual ASHPs across the urban and semi-urban geographies that we model.
- Efforts to improve national flexibility market access should support heat networks' participation and realise at least some of its benefits in reducing the need for more expensive lithium battery storage.
- Our modelling finds that heat networks could create savings of up to £1.2Bn in avoided generation installed capacity. This agrees with previous studies, which also show significant savings from a reduced need for offshore wind and solar capacity. Current market or strategic planning arrangements do not currently enable these savings to be realised. This needs to be a clear priority.
- The reduced grid costs associated with large heat networks with high levels of Thermal Energy Storage (TES) reflect the reduced operational burden on the grid. However, beyond local flexibility markets to manage local constraints, there are no current markets that would enable these savings for consumers and UK Plc to be realised.

Contents

Acronyms and abbreviations

Table 1 – acronyms used in report

Term	Definition
ASHP	Air Source Heat Pump
CCC	Climate Change Committee
COP	Coefficient Of Performance, used to describe the efficiency of heat pump technologies
DESNZ	Department for Energy Security and Net Zero
GSHP	Ground Source Heat Pump
H2 OCGT	Hydrogen Open Cycle Gas Turbine
NESO	National Energy System Operator
TES	Thermal Energy Storage
WeSIM	Whole electricity System Investment Model
WHR	Waste Heat Recovery
WSHP	Water Source Heat Pump

Introduction

Decarbonising heat is essential for the UK to meet its net zero emissions target by 2050. Heating buildings currently accounts for around one-third of the UK's greenhouse gas emissions due to the widespread use of natural gas[1, 2]. Achieving the decarbonisation of heating in the most cost-effective way therefore requires solutions that also consider the wider energy system, in particular the electricity system.

Heat networks can make a significant contribution to this goal, especially in urban and semi-urban areas. By supplying heat to multiple buildings from shared infrastructure, they use energy more efficiently and help manage the impact of heating on the power system[3, 4]. When combined with thermal storage, heat networks can shift electricity demand to off-peak periods, supporting the integration of renewable generation and reducing pressure on grid infrastructure[5, 6, 7]. They are also highly versatile, able to draw heat from a range of low-carbon sources such as large-scale heat pumps, biomass, or industrial waste heat, depending on what best fits the local context.

The Whole electricity System Investment Model (WeSIM)[8] is often used to assess how heating and electrification strategies affect the broader power system. WeSIM optimises long-term investment and short-term operation across generation, storage, and network assets to achieve the lowest overall system cost (Figure 2). It is widely used by government and industry to inform energy policy and infrastructure decisions. Applications of the model by the Committee on Climate Change (CCC), Ofgem, and the UK government have provided insights into the value of flexibility, system resilience, and investment needs in a low-carbon energy system[9, 10, 11].

Recent analysis using WeSIM has explored the system benefits of electrified heat networks on the electricity system. Research by Shahab *et al*. (2024) found that deploying heat networks at scale in the UK could reduce total system costs, improve renewable energy integration, and enhance system flexibility, generating total savings of up to £1.57 billion per year[12].

Building on this work, ADE Research has undertaken new analysis aligned with the priorities of industry and the Department for Energy Security and Net Zero (DESNZ). This study incorporates new inputs and refined policy scenarios developed in collaboration with government, academic, and industry experts. It examines how different network designs, levels of thermal storage, generation technologies, retrofit rates, and cost assumptions affect system outcomes. The findings provide a robust assessment of the electricity system benefits of heat networks, showing that these benefits are realised across all scenarios considered, through reductions in generation, storage, and infrastructure costs.

Figure 2: Overview of the WeSIM model

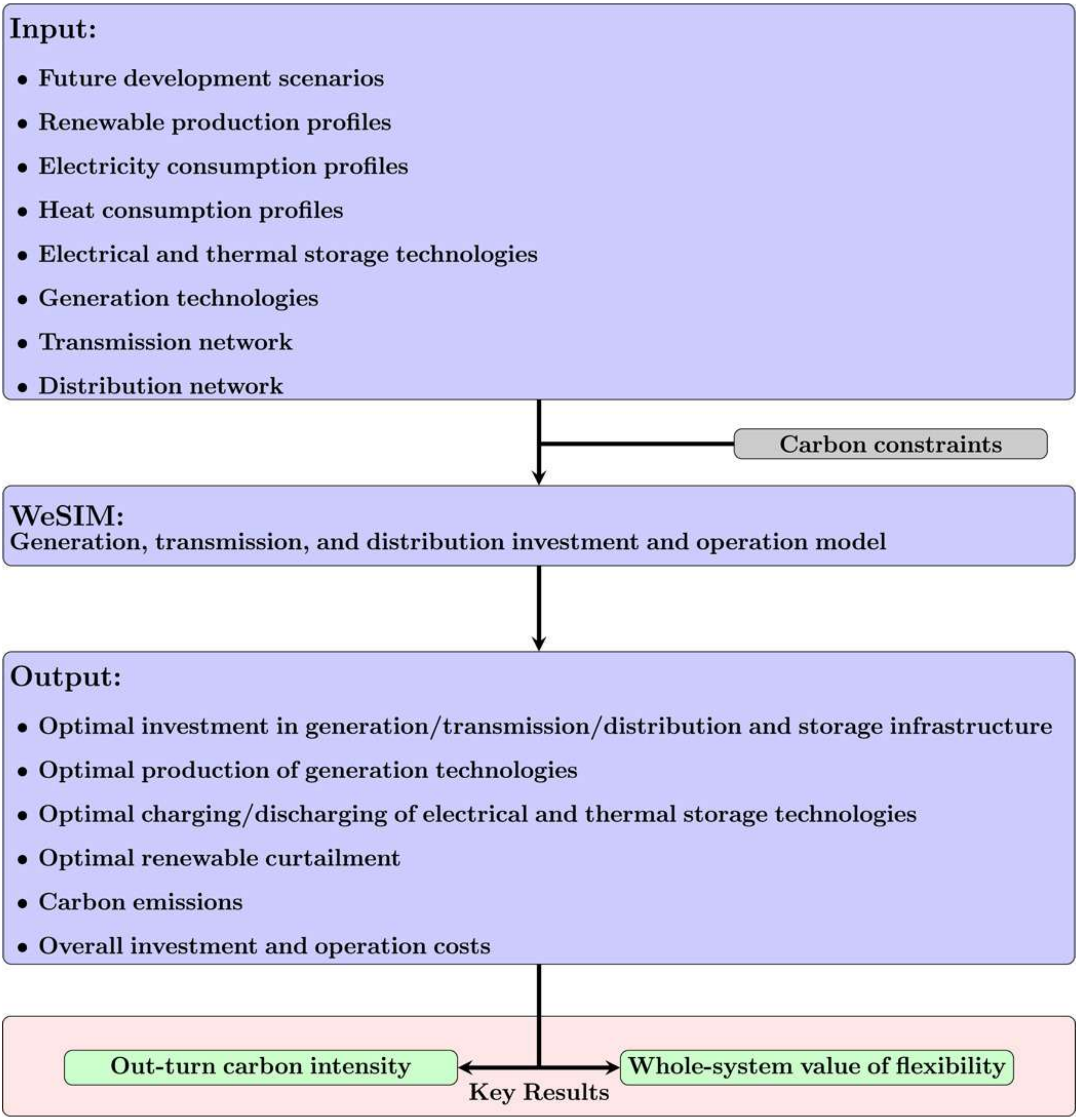


Figure 2: Schematic illustrating the Whole electricity System Investment (WeSIM) model (taken from Shahab *et al.*, 2024). WeSIM has been used by the CCC, Ofgem and the UK government to quantify the lowest investment pathways in a flexible, resilient, low-carbon energy system.

Methodology

We used the WeSIM model to investigate the net cost benefits of heat networks for the electricity system. To do so, we compared a range of scenarios to a baseline in which we assume no growth in heat networks from their current level, with small, urban-focused networks operating with limited Thermal Energy Storage (TES) and low flexibility. The difference in the cost to the electricity system between this baseline and the modelled scenario was then recorded, including how this is split out across infrastructure, generation, network and storage costs. A review of how these costs are defined, in addition to how we define various terms used in our modelling, is provided in the second annex (Annex 2: Detailed methodology & key assumptions). By doing so, we evaluate the cost-effectiveness, renewable energy integration, and system flexibility provided by heat networks under different deployment scenarios. Using the WeSIM model allows us to assign monetary values to these benefits, enabling a comprehensive analysis aligned with the UK's net-zero ambitions.

Building on the work of Shahab *et al.*, we therefore parameterised the WeSIM model by considering additional inputs and new scenarios for heat network deployment. The work to determine these inputs and scenarios was presented to a steering group with representatives from DESNZ, the National Energy Systems Operator (NESO), The National Grid, Ofgem, the academics Shahab Dehghan and Marko Aunedi, and industry figures across both the heat network and flexibility sectors. Input variables and scenarios were revised and developed through this engagement to ensure that there was broad consensus on the plausible conditions between now and 2050, for both heat networks and the counterfactual of individual, Air Source Heat Pumps (ASHPs), so that our analysis might yield the most informative insights for policy makers. An overview of these additional inputs that were not considered in previous research is provided below.

Additional model inputs:

1. **Inclusion of capital costs**

   Crucially, the £1.57bn value identified in *Dehghan et al*. does not account for CAPEX of delivering the heat network. As system benefits include offsetting the cost of upgrading electricity infrastructure, we have incorporated the capital costs of developing the heat network (including thermal storage CAPEX) and the operating costs (OPEX) to enable a direct comparison to be made.

2. **Exploring heat Network versatility**

   One of the great values of heat networks is their versatility regarding their heat source. The findings from *Dehghan et al.* are based on ASHP both driving heat networks and individual units as the counterfactual. We have built on this by exploring a range of scenarios where heat networks are driven by a realistic mix of ASHP, GSHP, waste heat recovery, and other sources[1, 13].

3. **Spatial modelling**

We have introduced spatial detail by differentiating between urban, semi-urban, and rural regions. This accounts for geographical variations to effectively stabilise grids with high renewable energy levels[1].

4. **Enhanced thermal storage complexity**

   We have considered the impacts of deploying thermal storage at different scales and its interactions with other flexibility measures like demand-side response[2], to allow us to better quantify the flexibility provided by district heating systems[3] (Phase 2 analysis).

5. **Scaling peak heat demand**

   The diversity factor associated with heat networks means that they have a lower peak demand within networks, relative to the counterfactual (individual Air Source Heat Pumps), to serve the same amount of heat to customers[14,15]. We have considered both the reduction in peak demand associated with heat networks, and how this scales with the size of the heat network, with the assumption that the reduction in peak heat within networks increases, relative to the individual ASHP counterfactual, as networks get larger. This is outlined fully in the second annex (Detailed methodology & key assumptions).

Project scope

In each scenario that we model we assume that, collectively, heat networks and individual ASHPs together meet 80% of UK heat demand. We assume that the remaining 20% of UK heat demand is met by other sources, such as hydrogen or boilers and biomass. This remaining 20% of UK heat demand was out of the scope of this project and we do not make any assumptions as to how this remaining 20% of UK heat demand is delivered, only that it is not met by either heat networks or individual heat pumps (a decision taken with help from our steering committee). The electricity system benefits that we model therefore derive from the proportion of the 80% of UK heat demand that is met by heat networks, in addition to assumptions surrounding the size of networks, heat peaks within networks; battery costs and retrofit.

Heat network deployment scenarios

To quantify the net benefits of heat networks for the electricity system, we split our analysis into two phases. In Phase 1, we held all parameters constant across both our baseline and our modelled scenario, changing only the level of heat network deployment and the ambition of flexible thermal storage (Table 2). This enabled us to isolate any net benefits as being directly attributable to the deployment of large heat networks with flexible thermal storage. In Phase 2, we repeated the analysis but over a wider range of scenarios, in which we tested the impact of varying: different deployment levels of heat networks, the level of flexible thermal storage within networks; levels of retrofit; battery costs; and scaling heat peaks within networks. The high-level results of our Phase 2 analysis are provided (Summary, Phase 2 results) and a full, detailed breakdown of these results for these further scenarios and their underlying methodology is provided in the first annex (Annex 1: Further scenario testing). Our Phase 1 modelling assumptions are outlined below.

Phase 1

- Main scenario: heat networks meet 30% of UK heat demand; mixed deployment (across urban and semi-urban areas), large heat networks with maximised flexibility; and a reduction in peak demand of 50% within networks, relative to a counterfactual of individual ASHPs
- This scenario was then re-run but with a reduction of peak demand of 30% within networks, relative to the counterfactual, to equalise this with the reduction in peak heat within networks that we assume in our baseline (small networks with a more similar peak heat to the counterfactual of individual ASHPs)

A full, detailed breakdown of all methodologies and modelling assumptions is provided in the second annex (Annex 2: Detailed methodology & key assumptions).

Summary of model assumptions and input parameters, Phase 1

A breakdown of the all the assumptions, input costs and model parameters across both the baseline and our main scenario in Phase 1 is provided in Table 2.

Table 2 – input assumptions and model parameters, Phase 1 analysis (Main Scenario)

Variable	**Baseline – no growth**	**Phase 1 – maximised deployment and flexibility**
Total UK heat demand (TWh)	439	439
Heat Network Penetration	3.25%	30%
Heat Pumps Penetration	76.75%	50%
Battery Storage Cost	£200 per kWh	£200 per kWh
Heat Network Deployment Area	100% urban	70% Urban, 30% Semi-Urban
Reduction in peak demand within heat networks, relative to counterfactual (individual, ASHPs)	30%	50%
Heat network CAPEX (£Bn)	14.225	129.727
Individual ASHP CAPEX (counterfactual)	420.9206	274.215
Thermal storage (TES)	1 MWh/MW with a 3-hour duration	3MWh per MW with a 48 duration
Thermal Storage CAPEX (£Bn/TWh)	2.59	2.59
Breakdown, generation technology within heat networks	WHR: 41.25%	WHR: 15%
	Biomass boilers: 5%	Biomass boilers: 10%
	GSHP: 13.75%	GSHP: 30%
	ASHP: 25%	ASHP: 33.75%
	WSHP: 15%	WSHP: 11.25%
Annual OPEX, HN (£Bn)	0.1423	1.2972

Electricity system benefits: results, Phase 1 modelling

Our main scenario was run with a 50% reduction in peak demand within individual heat networks, relative to the same amount of heat being delivered by individual ASHPs. This analysis was then re-run with a 30% reduction in peak demand within individual heat networks, relative to this counterfactual.

Under the 50% peak reduction assumption we see, relative to our baseline:

- Annual power consumption for electrified heat falls by 19 TWh
- Installed generation capacity decreases by 8.3 GW for offshore wind and 2.7 GW for solar PV, yielding £1.2 bn/year in annualised generation cost savings
- Required battery storage capacity falls by 8.1 GW, saving £0.45 bn/year
- Grid infrastructure cost savings total £0.21 bn/year (operation, interconnection, transmission), and £0.55 bn/year in distribution savings
- Investing in heat networks to deliver 30% of heat saves £1.1bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

This is summarised in Figure 3.

Figure 3: breakdown of net cost benefits of heat networks (Main Scenario)

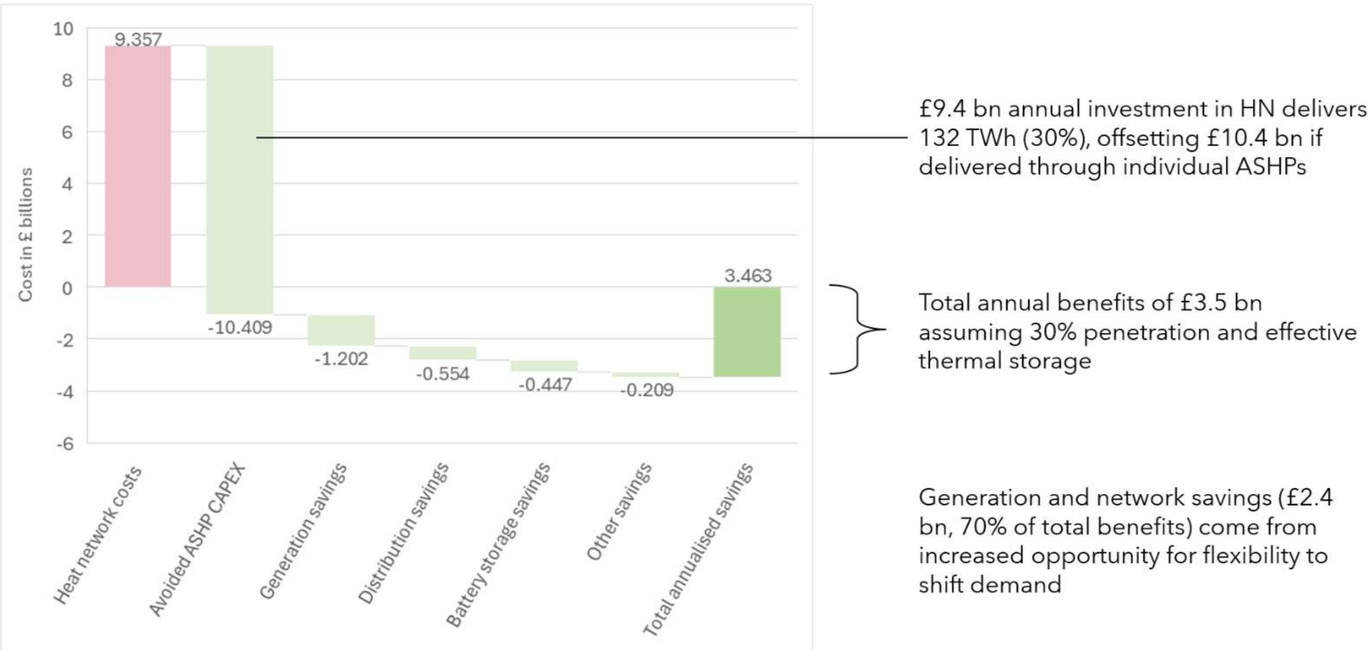


Figure 3: breakdown of the cost differences, relative to our baseline, of our main scenario (heat networks delivering 30% of UK heating). Total annual benefits come to £3.5 bn a year, of which £2.4 bn are generation and network savings.

Under the 30% peak reduction assumption (equal to the baseline):

- Annual power consumption for electrified heat falls by 18.7 TWh
- Installed generation capacity decreases by 18.4 GW for offshore wind and 2 GW for solar PV, delivering £1.18 bn/year in generation cost savings
- Battery storage capacity rises by 5.7 GW relative to baseline, shifting from a saving to an annualised cost of £0.16 bn/year
- Grid infrastructure savings (operation, interconnection, transmission) fall slightly to £0.18 bn/year, with £0.42 bn/year in distribution savings
- Investing in heat networks to deliver 30% of heat saves £1 bn/year in avoided CAPEX, relative to a baseline dominated by individual ASHPs

Comparing both scenarios (50% and 30% reduction of peak demand in networks with 30% penetration) to our baseline, in both cases we see a reduction in annual electricity demand, resulting in a reduction in installed generation capacity. However, when the reduction in peak heat demand within networks is set to 30% in our ambitious scenario, required battery capacity shifts from being a net saving (in our scenario with 50% reduction in peak demand within networks) to small a net cost (Figures 4 and 5). Across both scenarios, the deployment of heat networks to meet 30% of the UK's heat leads to substantial CAPEX savings, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs.

Figure 4: Annual power consumption of electricity demand across baseline and modelled scenarios

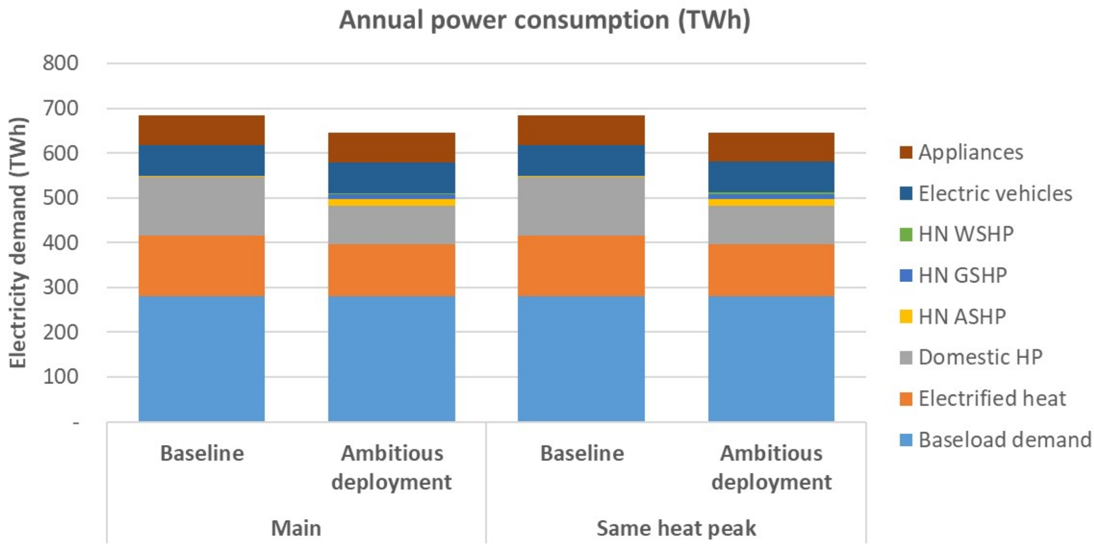


Figure 4: Outline of annual power consumption (electricity demand) across scenarios. "Electrified heat" represents electricity used for heating that is not supplied by heat pumps or heat networks. We see a reduction in annual electricity demand, relative to our baseline, regardless of assumptions of heat peaks within networks.

Figure 5: Installed generation capacity across baseline and modelled scenarios

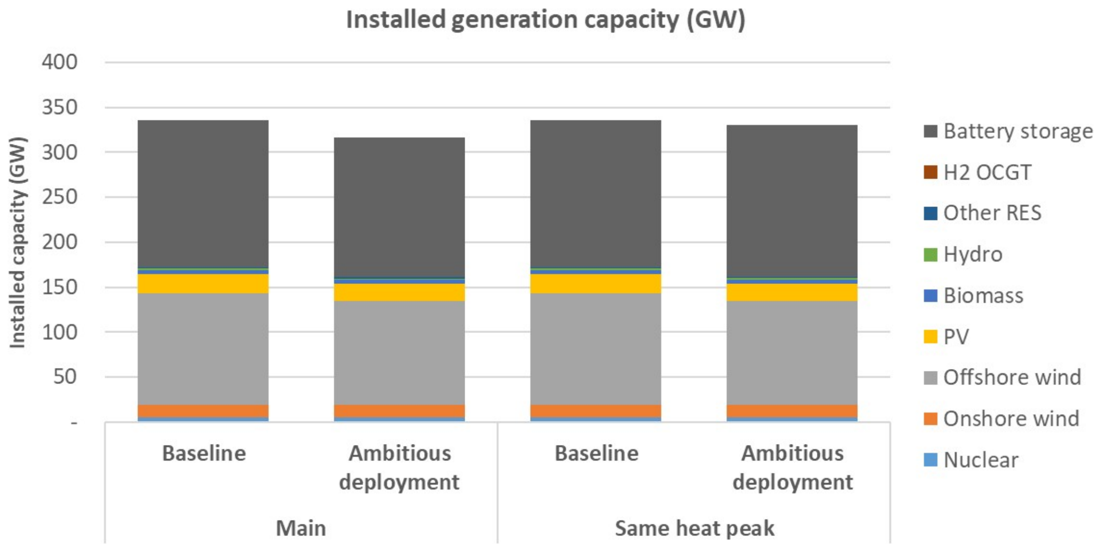


Figure 5: the difference in the required installed generation capacity in our main modelled scenarios, relative to our baseline. As a consequence of reduced electricity demand, there is a reduced requirement to install generation capacity, relative to our baseline.

Across both modelled scenarios (50% and 30% reduction of peak heat within networks), we see cost savings across grid infrastructure, in particular distribution savings (Figure 6).

Figure 6: Annualised network costs across baseline and modelled scenarios

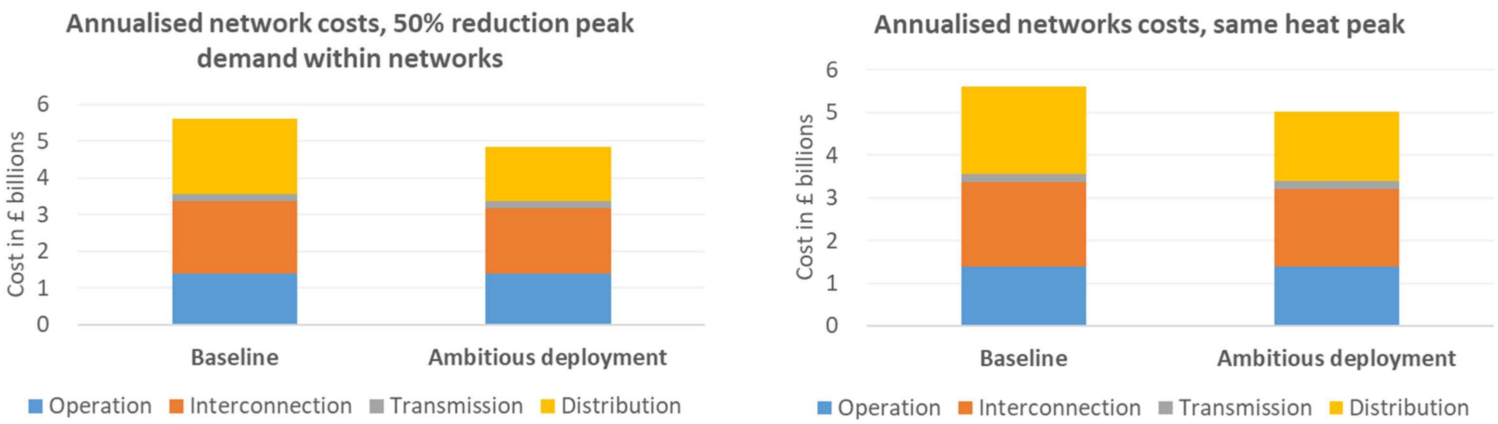


Figure 6: annualised network costs in our modelled scenarios, compared to our baseline. We see network costs fall in the modelled scenarios, primarily driven by a reduction in distribution costs.

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Modelling further scenarios

In addition to these results, we ran a second phase of modelling (Phase 2). The detailed results of this are included in the first annex (Annex 1: Further scenario testing). Here, we further developed our Phase 1 analysis over a wider range of scenarios, in which we tested the impact of varying: different deployment levels of heat networks; the level of flexible thermal storage within networks; levels of retrofit; battery costs; and scaling heat peaks within networks (Table 3). These different scenarios are summarised below.

Phase 2 scenarios

- Scenario 1: Heat networks meet 20% of UK heat demand; urban focus; small networks with limited flexibility; a reduction of peak demand within networks of 30%, relative to a counterfactual of individual ASHPs; high battery costs; some retrofit
- Scenario 2: Heat networks meet 20% of UK heat demand; mixed deployment; medium-sized networks with increased flexibility; a reduction of peak demand within networks of 40%, relative to a counterfactual of individual ASHPs; reduced battery costs; some retrofit
- Scenario 3: Heat networks meet 30% of UK heat demand; mixed deployment, large networks with maximised flexibility; a reduction of peak demand within networks of 50%, relative to a counterfactual of individual ASHPs; low battery costs; ambitious retrofit

Additionally, each of these Phase 2 scenarios were re-run with the following assumptions: first, holding battery costs constant across all 3 scenarios; then re-running all scenarios with the same reduction in peak demand within networks (holding this at 30% reduction of peak demand within networks, equalising this with the assumption made for the small networks in our baseline).

By running these further scenarios, we were able to test the sensitivity of our scenarios to key input costs (battery storage) and assumptions regarding the efficiency of networks (peak demand within networks). Moreover, it enabled us to test different policy scenarios and thus quantify whether the net benefits of heat networks for the electricity system scale in tandem with the extent to which they are deployed and the ambition of TES within networks.

A full breakdown of these results is provided in the first annex (Annex 1: Further scenario testing). The key conclusions from this further work are summarised below.

Summary, Phase 2 results

- Across all Phase 2 scenarios, we see net electricity system benefits associated with the deployment of heat networks
- These net benefits increase as the level of heat network deployment increases and as the scale of TES in networks increases
- Across all scenarios, we see generation savings associated with the reduced need to install generation capacity. Across all scenarios, we also see CAPEX savings in which it is cheaper to invest in heat networks across urban and semi-urban areas, rather than individual ASHPs

- When battery storage costs are equalised across our scenarios and our baseline, the flexibility provided by the TES within networks enable battery storage savings
- We see total savings across grid infrastructure and grid operation costs across all Phase 2 scenarios, which are consistently driven by distribution cost savings

Limitations

The following factors should be considered when interpreting this analysis:

1. **Static Cost Assumptions and No Economies of Scale:** Costs for retrofits, heat pumps, and heat networks are assumed constant. In reality, the first million retrofits may be more expensive due to less mature supply chains, higher labour costs, and a lack of standardisation. Over time, as experience and volumes increase, unit costs should decline. Similarly, large-scale heat network deployment could benefit from improved supply chains, bulk purchasing, and streamlined project management. Not accounting for these dynamics may overstate the long-term costs of scenarios with ambitious heat network deployment.
2. **No Policy Interventions or Market Evolution:** The current analysis does not consider policy measures (e.g., subsidies, carbon pricing, grants) that could lower early costs and help achieve scale more rapidly. Such measures might allow cost reductions and efficiency gains to materialise sooner, changing the relative economics of more ambitious pathways. Without considering how policy support or increasing experience in heat network deployment could lower capital costs, scenarios involving extensive heat networks and retrofits may appear less competitive than they could be under more realistic, evolving cost conditions.
3. **Thermal Energy Storage (TES):** The paucity of literature on TES CAPEX costs in heat networks meant that we took the figure for medium-scale TES storage and applied this universally, to avoid underestimating the TES CAPEX requirements (given the low £m/GWh associated with large scale TES). More accurate CAPEX data would give us more accurate results for the overall system's cost balance.
4. **The counterfactual:** For this analysis, we take as our counterfactual the assumption that households within the scope of this analysis have individual ASHPs. This enables us to effectively model the relative benefits of centralised heating via heat networks, when compared to decentralised heating provided via individual ASHPs. However, individual ASHPs may not always be a suitable counterfactual, depending on the dwelling type and the heart density of the area, while our current assumption is predicated on a policy environment where there is the widespread, mass adoption of ASHP. An alternative counterfactual might be for dwellings to be part of shared ground loop systems, in which dwellings have individual GSHP, but these are connected to a network via ambient loops. In this scenario, the potential penetration of heat networks is even greater and the energy demand from these networks much lower, given that GSHP require much less energy than ASHP to run. This is discussed further below.

Ideally, future research will be able to account for factors including inflation, the likely impact of innovation, better access to data, economies of scale and more nuanced counterfactuals. By correcting for these, we will be able to reduce the chances of overestimating the CAPEX requirements of heat networks and could feasibly model greater rates of network penetration.

Conclusions

This modelling exercise demonstrates the potential of heat networks to deliver substantial benefits to the UK energy system. The findings underscore the extent to which heat networks can provide net electricity system benefits, with cost savings across: the investment needed for generation capacity; battery storage; cost savings across electricity grid infrastructure and operation; and cost savings from investing in heat networks, rather than individual ASHPs, across urban and semi-urban areas. Collectively, these cost savings come to around £3.5 bn a year, with a cumulative net benefit of £86.5 bn by 2050. Importantly, we see substantial net system benefits irrespective of our assumptions for how heat peaks scale within networks. As these results are based on some fairly conservative assumptions, the true net benefits of heat networks are conceivably higher.

Investing in heat networks, rather than individual ASHPs, across the urban and semi-urban areas where we model heat network deployment saves £1.1 bn a year. Generation savings also make up a substantial part of the total cost savings (£1.2 bn a year), as reduced demand for electricity translates into a reduction in the installed generation capacity that is required. Ensuring that current strategic system planning and market arrangements are capable of realising these generation savings should therefore be prioritised. Reduced grid costs (£0.76 bn of cost savings a year, of which £0.55 bn are distribution cost savings) reflect the reduced operational burden on the grid, with reduced transmission and distribution costs arising from the improved opportunities for flexibility provided by high levels of TES. Distribution cost savings in particular show that heat networks are beneficial for distribution flexibility markets - efforts to improve market access and enablers for flexibility should help realise at least some of the benefits of heat networks being able to out-compete more expensive lithium battery storage.

These results could be underestimating the potential cost benefits of heat networks, as our analysis does not currently account for economies of scale and associated improvements in supply chains, bulk purchasing, and streamlined project management. We also do not factor in public subsidies which would offset initial capital costs and have been deliberately conservative with our assumptions regarding TES CAPEX. Additionally, our analysis was restricted to assuming no low temperature networks and we do not account for ambient ground loop systems in the model. This is due to a combination of lack of data (it is difficult to model CAPEX ratios etc. for these systems), and assumptions apropos the policy environment between now and 2050.

Our scenarios provide a clear comparison between centralised heating via networks and a decentralised counterfactual of individual ASHPs. However, the blanket assumption that our counterfactual is individual ASHP precludes the possibility that, for areas within heat network zones that cannot connect to the main network, a shared ground loop may be a viable alternative[16]. If the policy environment is conducive to this latter approach, then there is evidence that the cost benefits of heat networks could yet be higher still: research for Kensa by Element Energy demonstrates the potential for substantial reductions in both annual and peak electricity demand when using a system of networked GSHPs, with associated lower generation and grid capacity requirements[17]. In this research, Great Britan's peak electricity demand in 2050 could be reduced by up to 4GW (equivalent to Great Britain's typical winter capacity margin) by increasing GSHP from 15% to 38% of total heat pump installation. While our most ambitious scenario, Blaze, envisages GSHPs accounting for 30% of the generation technologies within heat networks – with associated savings in electricity demand - the use of shared ground loops could increase the deployment of this technology. In future research that includes a shared ground loops scenario in its modelling, the penetration rate of networks – and thus the associated cost benefits – could potentially be higher still. Forthcoming research by ADE, supported by extensive industry engagement, is expected to fill these critical evidence gaps. ADE Research has worked with industry stakeholders to synthesise detailed cost, performance, and applicability data for shared ground loops. This research is anticipated to further substantiate and potentially expand the recognised benefits of heat networks within future policy modelling and decisions.

Our analysis is very sensitive to minor changes to highly assumptive inputs. The inclusion of capital costs, spatial variability, scaling heat peaks within networks and modelling a variety of generation technologies significantly enriches previous analysis in this area, but this also generates opportunities for further research to pursue further how these considerations can be further tested and quantified.

To enhance these findings, future work should:

- Incorporate cost reductions over time due to technological advancements and market evolution.
- Reflect the impact of policy interventions, such as subsidies or carbon pricing.
- Present scenarios both with and without discounting, allowing for broader interpretation of costs and benefits.
- Have a more nuanced approach to the counterfactual of what centralised heat networks are compared against, with the consideration of shared ground loop systems as an alternative to individual ASHPs.

Addressing these factors will allow subsequent analyses to build on this work to continue to provide an actionable foundation for policymaking.

Rigorous research shows that heat networks deliver substantial net system benefits across a range of policy scenarios and assumptions. We demonstrate that large-scale, flexible heat networks can achieve long-term economic and environmental success and that their ambitious deployment will be a key, cost-effective strategy to meet Net Zero.

The lead author in ADE Research was Freddie Wilkinson, with support from Aaron Gould and Dr Philip Nicholson.

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Annex 1: Further scenario testing

In the second phase of our research, we kept the same assumptions for our baseline (no growth in networks from their current penetration of 3.25% and limited thermal storage). We then modelled three further scenarios to compare to this baseline in which we quantified electricity system benefits across different levels of ambition, not just regarding heat network deployment, but also considering changing battery costs and differing levels of both thermal storage and retrofit (with the latter having implications for total UK heat demand, which therefore differs across these scenarios). These scenarios are summarised below:

- **Scenario 1:** urban deployment, small networks, high battery costs, heat network penetration of 20%
- **Scenario 2:** urban & semi-rural deployment, medium-sized networks, reduced battery costs, heat network penetration of 20%
- **Scenario 3:** urban & semi-rural deployment, large networks, maximised flexibility, low battery costs, ambitious retrofit, heat network penetration of 30%

A detailed breakdown of key cost assumptions and parameters across these scenarios and our baseline is provided in Table 3.

Table 3: Overview of key cost inputs, model parameters and assumptions across our Phase 2 analysis

Variable	Baseline – No Growth	Scenario 1: urban focus, high battery costs	Scenario 2: mixed deployment with reduced battery costs	Scenario 3: maximised flexibility with Low battery costs
Total UK heat demand (TWh)	355	355	355	309
Proportion of EPC band D properties retrofitted to EPC band C	50%	50%	50%	100%
Cost of retrofit (£Bn)	41.43	41.43	41.43	82.86
Heat Network Penetration	3.25%	20%	20%	30%
Heat Pumps Penetration	76.75%	60%	60%	50%
Battery Storage Cost	£400 per kWh	£400 per kWh	£300 per kWh	£200 per kWh
Heat Network Deployment Area	100% urban	100% urban	70% Urban, 30% Semi-Urban	70% Urban, 30% Semi-Urban
Reduction in peak demand within heat networks, relative to counterfactual	30%	30%	40%	50%
Heat network CAPEX (£Bn)	11.50	67.69	69.94	91.31
Individual ASHP CAPEX (counterfactual)	340.38	266.09	266.09	193.13
Thermal storage	1 MWh/MW with a 3-hour duration	1 MWh/MW with a 3-hour duration	2 MWh/MW with a 8-hour duration	3MWh per MW with a 48 duration
Thermal Storage CAPEX (£Bn/TWh)	2.59	2.59	2.59	2.59
HN generation technology	WHR: 41.25%	WHR: 15%	WHR: 15%	WHR: 15%
	Biomass boilers: 5%	Biomass boilers: 15%	Biomass boilers: 10%	Biomass boilers: 10%
	GSHP: 13.75%	GSHP: 14%	GSHP: 22.5%	GSHP: 30%
	ASHP: 25%	ASHP: 52.5%	ASHP: 45%	ASHP: 33.75%
	WSHP: 15%	WSHP: 3.5%	WSHP: 7.5%	WSHP: 11.25%
Annual OPEX, Heat networks (£Bn)	0.11	0.86	0.90	1.17

Results, Phase 2 analysis

Across these scenarios, we see total, annualized net benefits to the electricity system of between £1.15bn - £6.45bn a year (Figure S1).

Figure S1: Annualised system benefits of heat networks, Phase 2 of modelling

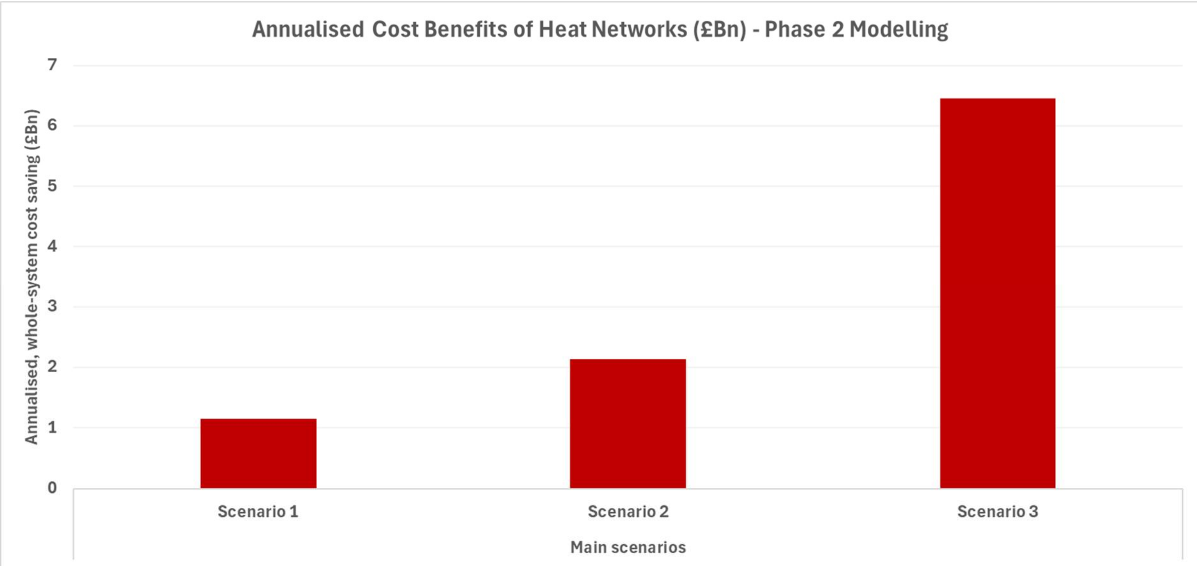

Figure S1: The annualised system benefits of heat networks across the 3 scenarios that we model in phase 2, relative to our baseline. We see cost savings increasing in tandem with the level of heat network deployment and the ambition of TES within networks.

In Scenario 1, relative to our baseline, we see:

- Annual power consumption for electrified heat falls by 8.8 TWh
- Installed generation capacity decreases by 3 GW for offshore wind, 0.5 GW for solar PV and 0.4 GW for biomass, but increases by 2.3 GW for H2 Open Cycle Gas Turbines (OCGT), cumulatively yielding £0.34 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 0.3 GW, costing £0.02 bn/year
- Grid infrastructure cost savings total £0.07 bn/year (operation, interconnection, transmission), and £0.22 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.53bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 2, relative to our baseline, we see:

- Annual power consumption for electrified heat falls by 9.3 TWh

- Installed generation capacity decreases by 3.9 GW for offshore wind, increases by 0.04 GW for solar PV and decreases by 5.65 GW for biomass and by 19.6 GW for H2 OCGT, yielding £2.1 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 20.7 GW, costing £0.76 bn/year
- Grid infrastructure cost savings total £0.02 bn/year (operation, interconnection, transmission), and £0.43 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.34bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 3, relative to our baseline, we see:

- Annual power consumption for electrified heat falls by 28.5 TWh
- Installed generation capacity decreases by 9.2 GW for offshore wind, by 5.3 GW for solar PV, by 5.7 GW for biomass and by 87.6 GW for H2 OCGT, yielding £6.9 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 87.6 GW, costing £2.21 bn/year
- Grid infrastructure cost savings total £0.12 bn/year (operation, interconnection, transmission), and £1.08 bn/year in distribution savings
- Investing in heat networks to deliver 30% of heat saves £3.73bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

Across all three scenarios, we see a reduction in the annual power consumption of electrified heat, with resulting decreases in the installed generation capacity which feed through into generation cost savings (Figures S2 and S3). All scenarios result in an increase in installed battery capacity, with increased costs relative to our baseline. Across all three scenarios, the deployment of heat networks to meet 20-30% of the UK's heat leads to substantial CAPEX savings, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs.

Figure S2: Annual power consumption (electricity demand) across modelled Phase 2 scenarios, relative to our baseline

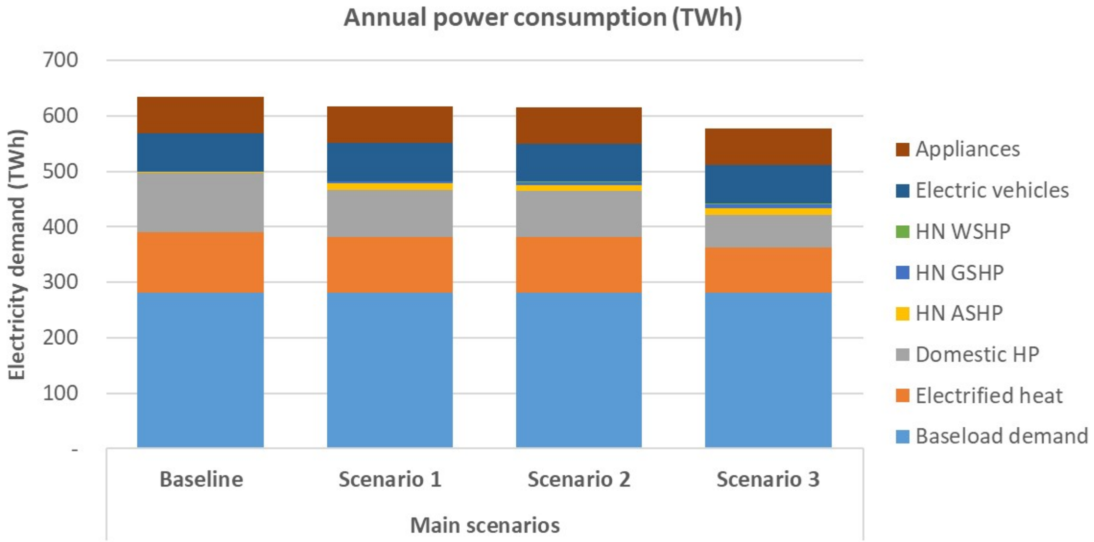

Figure S2: annual power consumption (electricity demand) across modelled Phase 2 scenarios. As the deployment of heat networks with large scale, flexible TES increases, we see a decrease in total electricity demand.

Figure S3: Installed generation capacity across modelled Phase 2 scenarios, relative to our baseline

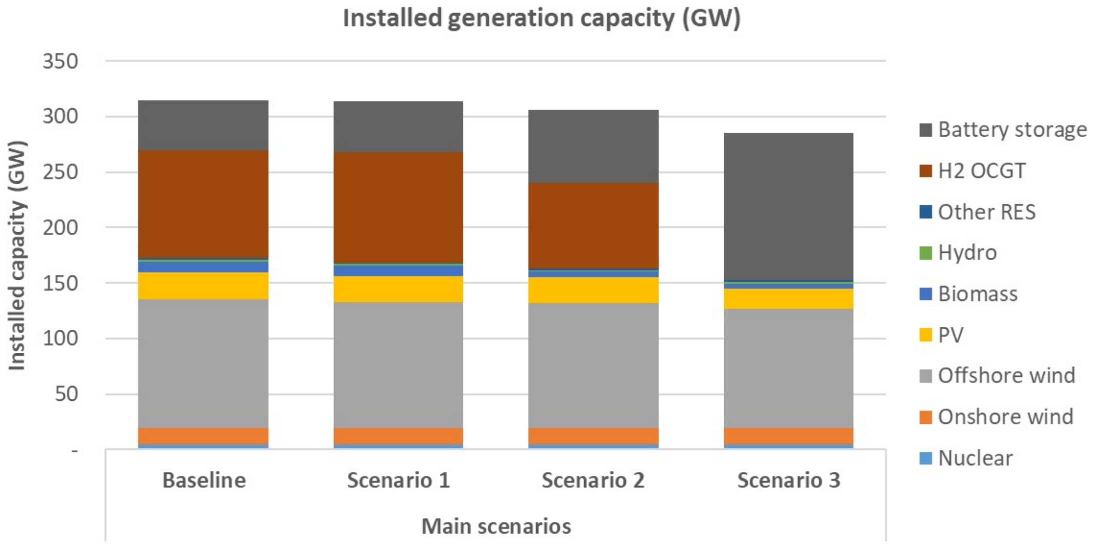

Figure S3: Installed generation capacity across our baseline and modelled scenarios. Installed capacity falls as the deployment of large heat networks with flexible TES increases. In Scenario 3 (heat network penetration of 30%), there is also a shift away from H2 OCGT as investment in battery storage is prioritised.

Across all three scenarios, we see cost savings across grid infrastructure, in particular distribution savings (Figure S4).

Figure S4: Annualised network costs across modelled Phase 2 scenarios, relative to our baseline

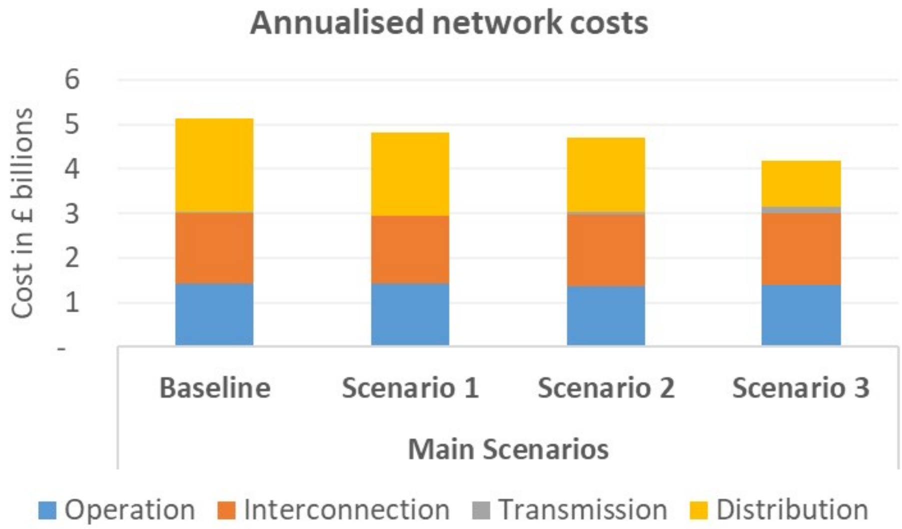

Figure S4: Annualised network costs savings across all Phase 2 modelled scenarios. Network cost savings increase with the level of deployment of large networks with large-scale, flexible TES, driven primarily by distribution cost savings.

Results, Phase 2.1analysis

We proceeded to re-run our three scenarios but equalised the cost of battery storage across each of these (including our baseline) to £200/kWh. We therefore assume low battery costs across all scenarios, while all other assumptions across our baseline and our model scenarios remained the same.

When we equalise battery costs across our baseline and all scenarios, we see total, annualized net benefits to the electricity system of between £1.24bn - £3.73bn a year (Figure S5).

Figure S5: Annualised system benefits of heat networks, Phase 2.1 of modelling, where all scenarios have equalised battery costs

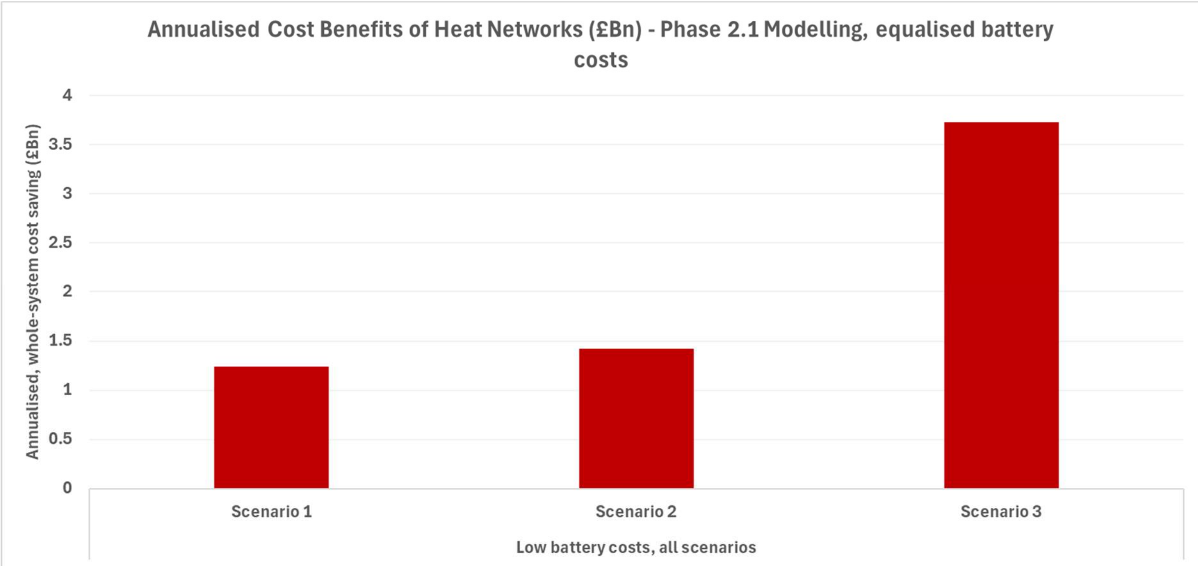

Figure S5: annualised system benefits of heat networks, Phase 2.1 modelling. Net cost savings increase as the level of ambition of heat network deployment increases, even when holding battery storage costs constant across all scenarios.

In Scenario 1, when battery costs are equalized (to £200/kWh both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 8.8 TWh
- Installed generation capacity decreases by 3 GW for offshore wind, 0.4 GW for solar PV and 0.01 GW for both biomass and H2 OCGT, yielding £0.42 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 2.1 GW, costing £0.06 bn/year
- Grid infrastructure cost savings total £0.12 bn/year (operation, interconnection, transmission), and £0.22 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.53bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 2, when battery costs are equalized (to £200/kWh both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 8.3 TWh
- Installed generation capacity decreases by 3.6 GW for offshore wind, by 0.4 GW for solar PV and decreases by 0.01 GW for biomass and 0.02 GW for H2 OCGT, yielding £0.49 bn/year in annualised generation cost savings
- Required battery storage capacity decreases by 3.9 GW, saving £0.21 bn/year

- Grid infrastructure cost savings total £0.12 bn/year (operation, interconnection, transmission), and £0.26 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.34bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 3, when battery costs are equalized (to £200/kWh both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 17.2 TWh
- Installed generation capacity decreases by 9.94 GW for offshore wind, by 0.42 GW for solar PV and by 0.01 for H2 OCGT, yielding £1.3 bn/year in annualised generation cost savings
- Required battery storage capacity decreases by 5.4 GW, saving £0.74 bn/year
- Grid infrastructure cost savings total £0.27 bn/year (operation, interconnection, transmission), and £0.62 bn/year in distribution savings
- Investing in heat networks to deliver 30% of heat saves £3.73bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

Across all three scenarios, we see a reduction in the annual power consumption of electrified heat, with resulting decreases in the installed generation capacity which feed through into generation cost savings (Figures S6 and S7). Scenarios 2 and 3 result in a decrease in installed battery capacity, with associated storage cost savings relative to our baseline. Across all three scenarios, the deployment of heat networks to meet 20-30% of the UK's heat leads to substantial CAPEX savings, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs.

Figure S6: Annual power consumption (electricity demand) across all modelled Phase 2.1 scenarios, battery costs equalised across baseline and all scenarios

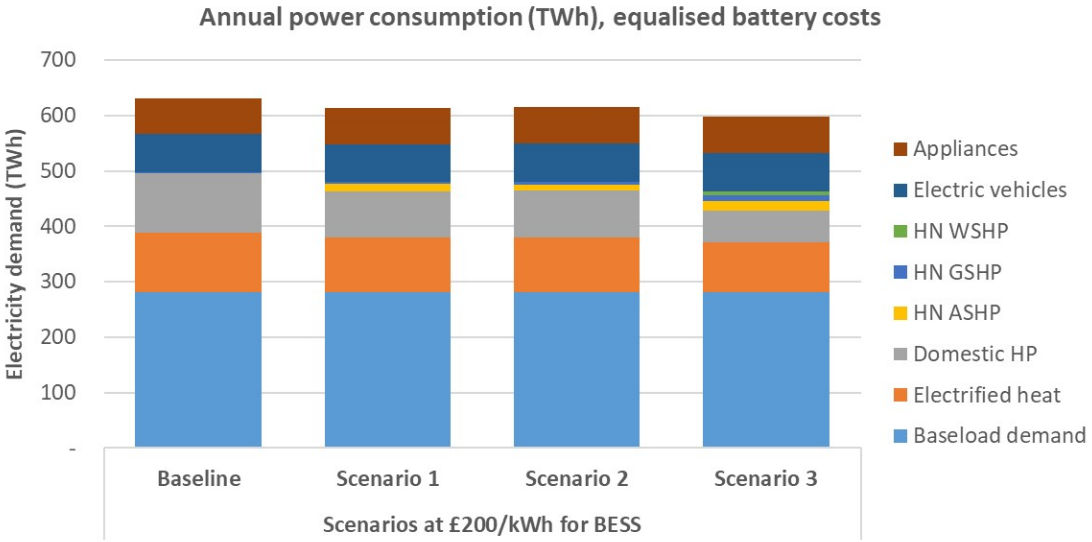

Figure S6: Annual power consumption (electricity demand) across all modelled phase 2.1 scenarios with equalised battery costs. Total electricity demand decreases as the deployment of large networks with large-scale, flexible TES increases.

Figure S7: Installed generation capacity across all modelled Phase 2.1 scenarios with equalised battery costs.

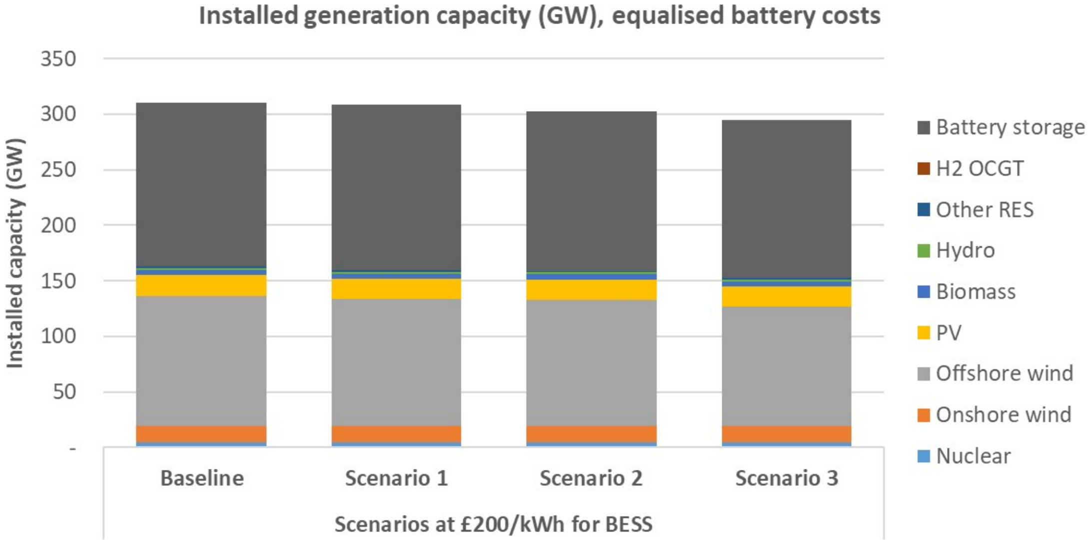

Figure S7: Installed generation capacity across all modelled Phase 2.1 scenarios with equalised battery costs. We see the required installed capacity decrease as the deployment of large networks with large-scale, flexible TES increases, reflecting the decrease in total electricity demand in these scenarios.

Across all three scenarios, we see cost savings across grid infrastructure, in particular distribution savings (Figure S8).

Figure S8: annualised network costs, equalised battery costs across all Phase 2.1 modelled scenarios and baseline

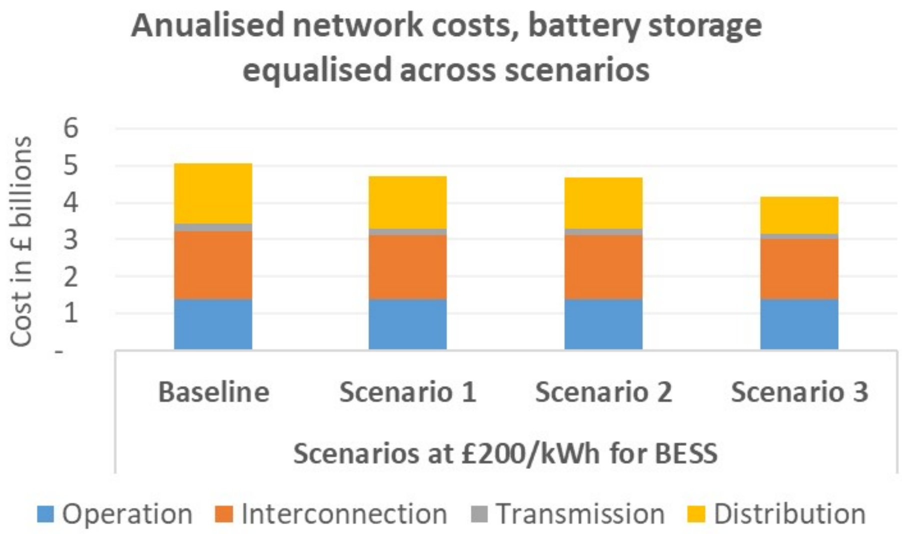

Figure S8: annualised network costs, equalised battery costs across all scenarios and baseline. Network costs decrease across all scenarios, relative to the baseline, driven primarily by a reduction in distribution costs.

Results, Phase 2.2 analysis

We re-ran our original Phase 2 scenarios but equalised the heat peak within networks. We therefore assume that all heat networks have a reduced heat peak of 30%, relative to a counterfactual of individual ASHPs, across both our baseline and the 3 modelled scenarios.

When we equalise the reduction in peak heat, relative to the counterfactual, across our baseline and all scenarios, we see total, annualized net benefits to the electricity system of between £0.82Bn - £5.90Bn a year (Figure S9).

Figure S9: *Annualised system benefits of heat networks, Phase 2.2 of modelling, same reduction in heat peak within networks across all scenarios and baseline*

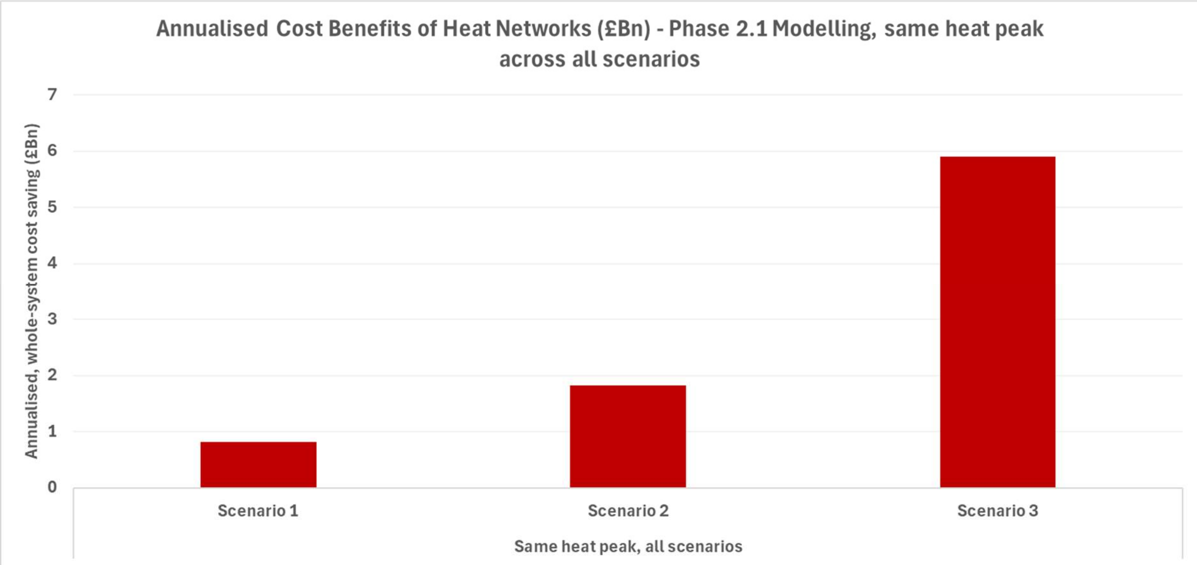

Figure S9: The annualised system benefits of heat networks, relative to our baseline, in which all scenarios (including baseline) assume the same peak heat reduction of within networks, relative to the counterfactual of individual ASHPs. As the level of deployment of heat networks with large-scale, flexible thermal storage increases, so do the net system benefits, with increasing cost savings.

In Scenario 1, when heat peaks within networks are equalized (30% reduction, relative to the counterfactual, both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 8.8 TWh
- Installed generation capacity decreases by 3 GW for offshore wind, 0.4 GW for solar PV, 0.9 GW for biomass and increases by 7 GW for H2 OCGT, cumulatively resulting in £0.17 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 1.2 GW, costing £0.11 bn/year
- Grid infrastructure cost savings total £0.06 bn/year (operation, interconnection, transmission), and £0.17 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.53bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 2, when heat peaks within networks are equalized (30% reduction, relative to the counterfactual, both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 9.2 TWh ade Research

- Installed generation capacity decreases by 1 GW for offshore wind, by 0.9 GW for solar PV, by 4.8 GW for biomass and decreases by 23.1 GW for H2 OCGT, yielding £1.95 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 20.2 GW, costing £0.8 bn/year
- Grid infrastructure (operation, interconnection, transmission) sees a small net cost, relative to the baseline, of £0.05bn/year. This is outweighed by £0.36 bn/year in distribution savings
- Investing in heat networks to deliver 20% of heat saves £0.34bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

In Scenario 3, when heat peaks within networks are equalized (30% reduction, relative to the counterfactual both here and in our baseline), we see the following cost differences, relative to our baseline:

- Annual power consumption for electrified heat falls by 28.2 TWh
- Installed generation capacity decreases by 5.1 GW for offshore wind, by 5.7 GW for solar PV and by 81.4 GW for H2 OCGT, yielding £6.9 bn/year in annualised generation cost savings
- Required battery storage capacity increases by 75.8 GW, costing £2.6 bn/year
- Grid infrastructure (operation, interconnection, transmission) sees a net cost, relative to the baseline, of £0.16 bn/year. This is outweighed by £0.98 bn/year in distribution savings
- Investing in heat networks to deliver 30% of heat saves £3.73bn a year in avoided CAPEX, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs

Across all three scenarios, we see a reduction in the annual power consumption of electrified heat, with resulting decreases in the installed generation capacity which feed through into annualised generation cost savings (Figures S10 and S11). However, across these scenarios, we also see an increase in the required battery capacity, leading to increased battery storage costs, relative to the baseline. Across all three scenarios, the deployment of heat networks to meet 20-30% of the UK's heat leads to substantial CAPEX savings, relative to our baseline where heat networks continue to meet 3.25% of heat, with the difference made up by individual ASHPs.

Figure S10: Annual power consumption (electricity demand), all modelled Phase 2.2 scenarios (same reduction in heat peak within networks across all scenarios)

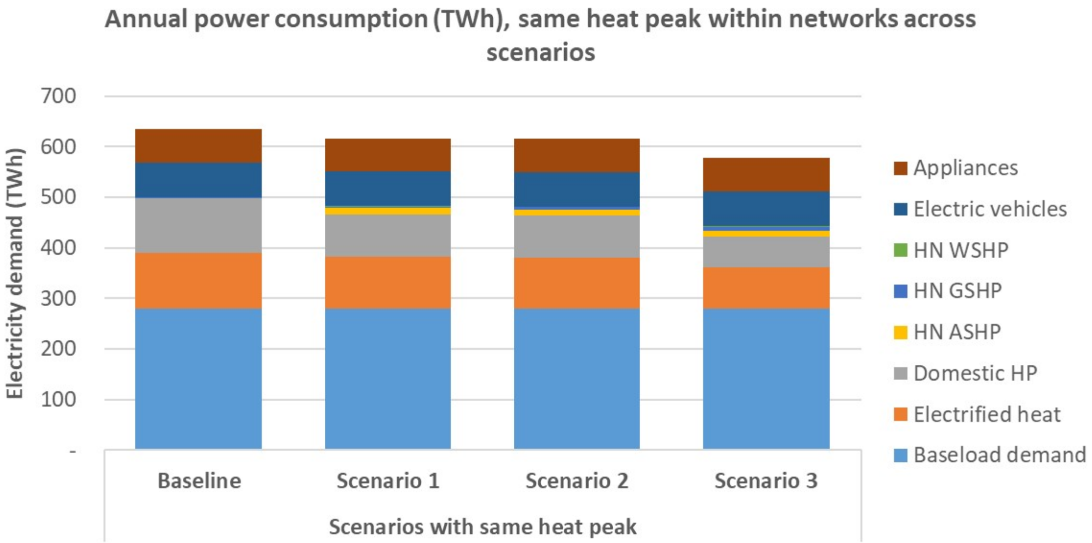

Figure S10: Annual power consumption (electrified heat) decreases as the deployment of large, flexible heat networks increases. All scenarios (including baseline) assume the same peak heat reduction within networks, relative to the counterfactual of individual ASHPs.

Figure S11: installed generation capacity across all modelled Phase 2.2 scenarios (same reduction in heat peak within networks across all scenarios)

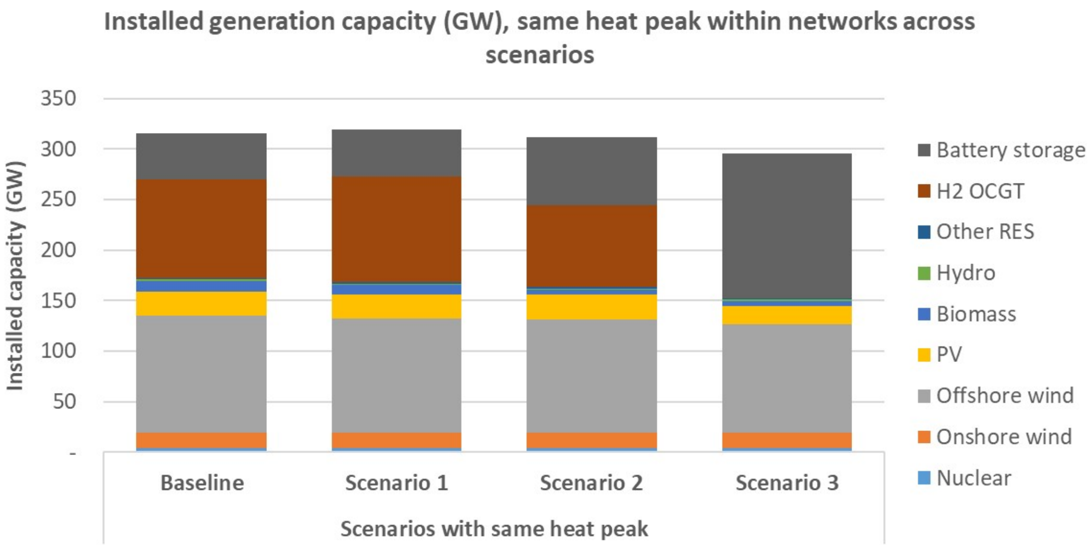

Figure S11: Installed generation capacity decreases as the deployment of large, flexible heat networks increases. All scenarios (including baseline) assume the same peak heat reduction within networks, relative to the counterfactual of individual ASHPs. In Scenario 3 (30% penetration of heat networks), there is a shift away from H2 OCGT as investment in battery storage is prioritised.

Across these three scenarios, we either see small cost savings associated with operation, interconnection, transmission (Scenario 1), or we see a small cost increase, relative to our baseline (Scenarios 2 and 3). In each scenario, this is outweighed by the distribution cost savings (Figure S12).

Figure S12: Annualised network costs across all modelled Phase 2.2 scenarios (same reduction in heat peak within networks across all scenarios)

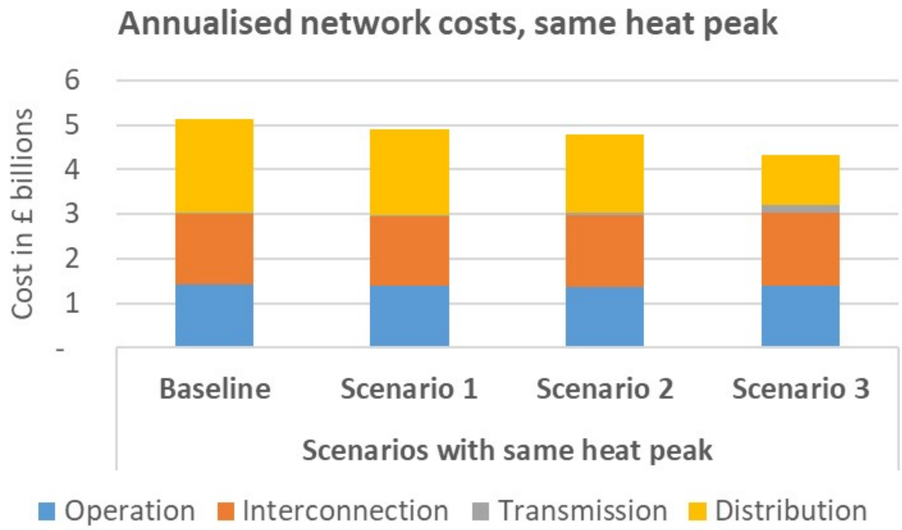

Figure S12: Annualised network costs decrease as the deployment of large, flexible heat networks increases. All scenarios (including baseline) assume the same peak heat reduction within networks, relative to the counterfactual of individual ASHPs. This is primarily driven by decreases in distribution costs.

Annex 2: Detailed methodology & key assumptions

Definitions of model terms and outputs

All of the definitions of the terminology used to describe model inputs, model outputs and how these relate to our policy scenarios are outlined in Table 4 below.

Table 4: Definitions of model inputs and outputs

Term	Definition
Baseline	The scenario against which all model outputs are compared to. In our baseline, we assume no growth in heat networks from their current level. We therefore assume a heat network penetration of 3.25% and an individual heat pump penetration of 76.75% with small, urban-focused heat networks operating with limited thermal storage and low flexibility.
Battery storage costs	The capital and operational costs of deploying electrical storage assets, including the costs for siting, installing and operating this type of storage.
CAPEX	Capital Expenditure
Counterfactual	In this research, we assume that heat networks and individual, Air Source Heat Pumps (ASHPs) collectively provide 80% of UK heat. The scope of this research only focuses on the 80% of heat demand assumed to be supplied by these technologies. In our modelling, if heat demand is not met by heat networks, then we assume it is met by the counterfactual of individual ASHPs.
Distribution costs	The investment and operation costs for the low-voltage networks that deliver electricity from substations to end consumers, e.g. upgrades due to distributed generation, local flexibility assets and increased demand.
Diversity Factor	The temporal spread of power peaks from individual consumers using a heat network. The diversity factor is the ratio between the maximum heat load at a network's energy centre and the sum of all the individual power peaks of the individual consumers using the network.
Generation costs	The capital and fixed costs associated with building new electricity generation capacity, including all generation technologies and the costs for repowering or decommissioning assets.
Heat network penetration	The proportion of UK heat demand that is met by heat networks by 2050 in the modelled scenario.
Heat peak within networks	The peak heat demand that a heat network meets. Due to the diversity factors associated with networks, the power peaks of all the individual consumers never occur at exactly the same time. The peak demand the network experiences is therefore less than the sum of the individual power peaks from all the individual consumers.
Interconnection costs	The costs associated with building and operating cross-border electricity interconnectors, e.g. investment in new cables and substations and the costs for maintaining and utilising these assets.
Mixed Deployment	Heat networks are deployed in both urban and semi-urban areas
Operation costs	OPEX costs for the expenses associated with running power system assets, e.g. fuel costs, maintenance, variable operating costs and any carbon-related costs for fossil fuel generation.
OPEX	Operational Expenditure
Transmission costs	Investment and operational costs for high-voltage national grid infrastructure (lines, substations, transformers). This includes reinforcement costs required to accommodate new generation, system upgrades for demand and renewables and the cost of maintaining system reliability.
Urban Deployment	Heat networks are deployed in urban areas

Heat peaks within networks

Across the different scenarios in our analysis, we assume different sizes of heat network to reflect varying levels of ambition in heat network deployment, assuming that, as ambition increases, networks are larger and not confined to urban areas. As a consequence, we assume that, in scenarios where heat networks are larger, the degree of dispersion among the peak loads of individual consumers is increased and that there is therefore an increase in non-coincident peak usage[14, 15]. If the power peaks of all consumers do not occur at the same time, then the required heat output is lower than the sum of all the power peaks of the individual consumers. In large heat networks this means that, even though the total annual demand remains the same, the peak load is reduced and the demand profile is flattened. Relative to a counterfactual of individual ASHPs, heat networks therefore have a flatter demand profile when meeting the same level of heat demand. As networks get larger, the peak heat within networks therefore continues to decrease, relative to the counterfactual. Our assumptions of this reduction of the heat peak within networks, relative to the counterfactual, are set out below. As the relationship between network size (number of connections) and peak heat reduction is not linear, we assume a range of connections for each typical network size.

Scaling heat peaks within networks

- Phase 2, Scenario 1: small, urban focused heat networks with up to ~80 connections, leading to a decrease in peak heat demand within networks of 30%, relative to the counterfactual of individual ASHPs[15, 18]
- Phase 2, Scenario 2: medium-sized networks with mixed deployment (urban and semi-urban) and a typical network size of ~80 – 200 connections, with a decrease in peak heat within networks of 40%, relative to the counterfactual[15, 18]
- Phase 2, Scenario 3: large networks with mixed deployment, with networks having 250 or more connections, with a decrease in peak heat within networks of 50%, relative to the counterfactual[15, 18]

Scaling flexible thermal storage within networks

In our Phase 2 modelling, we model different levels of flexible thermal storage within networks. A summary of this is provided below, with further detail shown in Table 5.

- Phase 2, Scenario 1: TES within networks facilitates limited demand shifting: storage is short-cycle, high discharge
- Phase 2, Scenario 2: Grid-responsive TES within networks enables medium-cycle load balancing
- Phase 2, Scenario 3: TES within networks facilitates strategic electricity demand shifting, with long-term buffering and multi-day peak shifting

Table 4: Assumptions for how TES within heat networks scales across the scenarios modelled in Phase 2 analysis

Factor	**Scenario 1: small networks (low storage)**	**Scenario 2: medium networks (medium storage)**	**Scenario 3: large networks (high storage)**
Total Storage Duration	3 hours	8 hours	48 hours
Storage per MW	1 MWh per MW	2 MWh per MW	3 MWh per MW
ASHP Share within heat networks	52.50%	45%	33.75%
GSHP + WSHP Share within heat networks	17.50%	30%	41.25%
Biomass Share within heat networks	15%	10%	10%
Storage Role	Short-cycle, high-discharge	Medium-cycle, load balancing	Long-term buffering, multi-day peak shifting
Grid Interaction	Limited demand shifting	Grid-responsive storage	Strategic electricity demand shifting
Reduction of Peak Demand (Relative to Counterfactual)	30%	40%	50%
Rationale	Networks are small and urban-focused. Storage is used for peak shaving and balancing ASHP variability.	Networks are larger and there is suburban as well as urban coverage. Increased reliance on low-carbon sources (heat pumps, waste heat) requires load shifting for daily balancing. Storage enables some grid interaction.	Networks are large and there is both suburban and urban coverage. High reliance on GSHP, WSHP & ASHP (75%) means longer storage supports grid balancing & demand response. Avoids excessive reliance on peak electricity demand during cold spells.

Constant parameters

Constants are parameters held fixed across all scenarios to ensure effective comparison:

Table 5: constant parameters across all scenarios

Heat Demand Met by Heat Networks and Heat Pumps	80% of total heat demand, with the remaining 20% supplied by hydrogen boilers, biomass and other sources (This remaining 20% of UK heat demand was out of the scope of this project).
Heat Pump Thermal Storage	Present in 30% of all individual heat pump installations. This assumption is based on the likelihood that new builds will incorporate thermal storage, while retrofits face consumer reluctance due to space constraints. Roughly 30% of existing stock are thought to have hot water cylinders, and it is assumed those currently without will resist installing TES unless mandated.
Heat Network Thermal Storage	Thermal storage in heat networks has been standardised at £2.59Bn/TWh across all scenarios. This was done to ensure that storage costs were not being overestimated for small networks or underestimated for large networks.
Individual ASHP CAPEX	Individual ASHP CAPEX is assumed as £1.249Bn/TWh. This takes account of the average cost of both purchasing and installing an ASHP, which we assume to be £14,912[19,20]. We assume the upper estimate of purchase and installation to accommodate the fact that we do not include OPEX or REPEX costs for individual ASHPs in our modelling and assume a preferential interest rate for ASHP CAPEX.
CAPEX for Heat Networks	As detailed in Table 7, CAPEX varies by generation technology, with heat network CAPEX averaged across all heat pump technologies equating to £1.059 Bn/TWh, calculated using DESNZ Heat Network Project Pipeline data.
Interest rate	The interest rate for both heat network and individual ASHP CAPEX is set at 5% (see below).

CAPEX assumptions for heat networks

Table 6: Mean CAPEX for Heat Networks by Generation Technology

Generation Technology	**Mean CAPEX (£Bn/TWh)**
Heat Pumps (all generation technologies)	1.059[1]
Waste Heat Recovery	0.985[2]
Biomass boiler	0.428[3]

COP assumptions, heat pump technologies

In addition, we assume the following Coefficient of Performance (COP) ratios for each heat pump technology, which are held constant across all scenarios:

- COP of 3 for ASHP
- COP of 3.5 for GSHP
- COP of 4 for WSHP

TES CAPEX within heat networks

CAPEX for thermal energy storage within heat networks has been standardised across all scenarios due to a paucity of cost data in the literature, resulting in the need to ensure that we are not over-estimating or underestimating costs in our scenarios. In designing our scenarios, we originally made the following assumptions apropos thermal storage:

- ***Small networks (in baseline and Scenario 1 in Phase 2 analysis)***
  - Literature describing small-scale storage systems suggested TES CAPEX is £17.2Bn/TWh for these systems[21], however this is focused on individual, dwelling-level storage, as opposed to network-level storage. As such, there were concerns that we were over-estimating the TES CAPEX in this scenario.
- ***Medium-sized networks (Scenario 2 in Phase 2 analysis)***
  - From the literature, we sourced the TES figure for medium-sized thermal storage, which we set as £2.59Bn/TWh[22].

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[1] To account for sample size, CAPEX ratios were calculated using all varieties of heat pump listed in DESNZ project pipeline data and averaged out across the whole suite of technologies, before being sense-checked by our steering group.
[2] Due to an absence of reliable data, EfW values have been used as a conservative proxy for waste heat recovery.
[3] Due to the small sample size in the DESNZ Project Pipeline data for projects utilising biomass boilers (n = 4), the CAPEX ratio calculated here was further sense-checked against other sources to ensure that this was not an underestimate:
Gwasanaeth Ynni Energy Service, Regional energy strategies Technical annex B: Economic modelling, Table 9, p.13
Regional energy strategies Technical annex B: Economic modelling
Climate Change Committee, Biomass in a low-carbon economy, Section 4.5, p. 148
Biomass in a low-carbon economy - Climate Change Committee

- ***Large networks (Main scenario, Phase 1 analysis and Scenario 3, Phase 2 analysis)***
  - The storage costs discussed in the literature for large-scale storage are £0.422Bn/TWh,[21, 23] which reflects the high-cost efficiency per unit of energy stored, but may not adequately factor in the upfront costs associated with the large-scale infrastructure required. As such we were concerned that we could be underestimating the CAPEX required in this scenario.

To avoid overestimating TES CAPEX in either our baseline or in Scenario 1, Phase 2, or underestimating TES CAPEX in either of our main scenario (Phase 1) or Scenario 3, Phase 2, we therefore decided to universally apply the TES figure for medium-sized thermal storage, which we set as £2.59Bn/TWh[22]. This is standardised as a constant across all scenarios in all phases of analysis.

Pricing and interest rates

Costs have been kept in 2024 prices. Calculations assume a 5% interest rate pa[24] for 25 years: though infrastructure projects of this nature have a typical lifespan of ~40 years, we calculated the net benefits up to and including 2050 in line with the UK's Net Zero Emissions Targets. Given the significant sensitivity of the analysis to highly unpredictable assumptions about interest rates and rates of deployment, and for comparability with benefits, we have assumed 2024 values over the assumed 25-year deployment of heat networks between now and 2050.

Interest rates are held at 5% for both individual ASHPs and heat networks so that CAPEX finance is treated equally across both technologies, despite evidence that the interest rate for individual ASHPs can be substantially higher (up to 9.9%)[25, 26, 27].

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